TRANSCANADA CORP
Form 40-F
February 21, 2014

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U.S. Securities and Exchange Commission

Washington, D.C. 20549

Form 40-F

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

OR

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

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

TRANSCANADA CORPORATION

(Exact Name of Registrant as specified in its charter)

Canada
(Jurisdiction of incorporation or organization)

4922, 4923, 4924, 5172
(Primary Standard Industrial Classification Code Number (if applicable))

Not Applicable
(I.R.S. Employer Identification Number (if applicable))

TransCanada Tower, 450 - 1 Street S.W.
Calgary, Alberta, Canada, T2P 5H1
(403) 920-2000
(Address and telephone number of Registrant's principal executive offices)

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

Securities registered pursuant to section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares (including Rights under Shareholder Rights Plan)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

For annual reports, indicate by check mark the information filed with this Form:

ý Annual Information Form ý Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

At December 31, 2013, 707,441,314 common shares;
22,000,000 Cumulative Redeemable First Preferred Shares, Series 1;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 3;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 5; and
24,000,000 Cumulative Redeemable First Preferred Shares, Series 7
were issued and outstanding

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the *Exchange Act* during the preceding 12 months (or such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). Yes ý No o

The documents (or portions thereof) forming part of this Form 40-F are incorporated by reference into the following registration statements under the *Securities Act of 1933*, as amended:

Form	Registration No.
S-8	333-5916
S-8	333-8470
S-8	333-9130
S-8	333-151736
S-8	333-184074
F-3	33-13564
F-3	333-6132
F-10	333-151781
F-10	333-161929
F-10	333-192561

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

Except sections specifically referenced below which shall be deemed incorporated by reference herein and filed, no other portion of the TransCanada Corporation 2013 Annual report to shareholders except as otherwise specifically incorporated by reference in the TransCanada Corporation Annual information form shall be deemed filed with the U.S. Securities and Exchange Commission (the "Commission") as part of this report under the Exchange Act.

A. Audited Annual Financial Statements

For audited consolidated financial statements, including the auditors' report, see pages 97 through 164 of the TransCanada Corporation 2013 Annual report to shareholders included herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 1 through 96 of the TransCanada Corporation 2013 Annual report to shareholders included herein under the heading "Management's discussion and analysis".

C. Management's Report on Internal Control Over Financial Reporting

For management's report on internal control over financial reporting, see "Report of management" that accompanies the audited consolidated financial statements on page 97 of the TransCanada Corporation 2013 Annual report to shareholders included herein.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an Annual Report on Form 40-F arises; or transactions in said securities.

DISCLOSURE CONTROLS AND PROCEDURES

For information on disclosure controls and procedures, see "Other information Controls and procedures" in Management's discussion and analysis on page 82 of the TransCanada Corporation 2013 Annual report to shareholders.

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's board of directors has determined that it has at least one audit committee financial expert serving on its audit committee. Mr. Kevin E. Benson and Mr. Richard E. Waugh have been designated audit committee financial experts and are independent, as that term is defined by the New York Stock Exchange's listing standards applicable to the Registrant. The Commission has indicated that the designation of Mr. Benson and Mr. Waugh as audit committee financial experts does not make Mr. Benson or Mr. Waugh an "expert" for any purpose, impose any duties, obligations or liability on Mr. Benson or Mr. Waugh that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee.

CODE OF ETHICS

The Registrant has adopted a code of business ethics for its directors, officers, employees and contractors. The Registrant's code is available on its website at www.transcanada.com. No waivers have been granted from any provision of the code during the 2013 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For information on principal accountant fees and services, see "Audit committee Pre-approval policies and procedures" and "Audit committee External auditor service fees" on pages 38 and 39 of the TransCanada Corporation Annual information form.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements, as defined in this Form, other than the guarantees and commitments described in Note 26 of the Notes to the consolidated financial statements attached to this Form 40-F and incorporated herein by reference.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For information on tabular disclosure of contractual obligations, see "Contractual obligations" in Management's discussion and analysis on page 72 of the TransCanada Corporation 2013 Annual report to shareholders.

IDENTIFICATION OF THE AUDIT COMMITTEE

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

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

FORWARD-LOOKING INFORMATION

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

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

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

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

expected industry, market and economic conditions.

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

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

Assumptions

inflation rates, commodity prices and capacity prices

timing of financings and hedging

regulatory decisions and outcomes

foreign exchange rates

interest rates

tax rates

planned and unplanned outages and the use of our pipeline and energy assets

integrity and reliability of our assets

access to capital markets

anticipated construction costs, schedules and completion dates

acquisitions and divestitures.

Risks and uncertainties

our ability to successfully implement our strategic initiatives

whether our strategic initiatives will yield the expected benefits

the operating performance of our pipeline and energy assets

amount of capacity sold and rates achieved in our pipelines business

the availability and price of energy commodities

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

regulatory decisions and outcomes

outcomes of legal proceedings, including arbitration

performance of our counterparties

changes in the political environment

changes in environmental and other laws and regulations

competitive factors in the pipeline and energy sectors construction and completion of capital projects

costs for labour, equipment and materials

access to capital markets

interest and foreign exchange rates

weather

cyber security

technological developments

economic conditions in North America as well as globally.

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

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

SIGNATURES

Pursuant to the requirements of the *Exchange Act*, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

TRANSCANADA CORPORATION

Per: /s/ DONALD R. MARCHAND

DONALD R. MARCHAND
Executive Vice-President and Chief Financial Officer

Date: February 21, 2014

DOCUMENTS FILED AS PART OF THIS REPORT

13.1	TransCanada Corporation Annual information form for the year ended December 31, 2013.
13.2	Management's discussion and analysis (included on pages 1 through 96 of the TransCanada Corporation 2013 Annual report to shareholders).
13.3	2013 Audited consolidated financial statements (included on pages 97 through 164 of the TransCanada Corporation 2013 Annual report to shareholders), including the auditors' report thereon and the Report of Independent Registered Public Accounting Firm on the effectiveness of TransCanada's internal control over financial reporting as of December 31, 2013.
EXHIBITS	
23.1	Consent of KPMG LLP, Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the *Sarbanes-Oxley Act of 2002*.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the *Sarbanes-Oxley Act of 2002*.
32.1	Certification of Chief Executive Officer regarding Periodic Report containing Financial Statements.
32.2	Certification of Chief Financial Officer regarding Periodic Report containing Financial Statements.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

TransCanada Corporation

2013 Annual information form

February 19, 2014

Table of 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, 2013 (**Year End**). Amounts are expressed in Canadian dollars unless otherwise indicated. Information in relation to metric conversion can be found at *Schedule A* to this AIF. The *Glossary* found at the end of this AIF contains certain terms defined throughout this AIF and abbreviations and acronyms that may not otherwise be defined in this document.

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

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

Forward-looking information

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

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

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

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

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

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

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

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

Assumptions

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

regulatory decisions and outcomes

foreign exchange rates

interest rates

tax rates

planned and unplanned outages and the use of our pipeline and energy assets

integrity and reliability of our assets

access to capital markets

anticipated construction costs, schedules and completion dates

acquisitions and divestitures.

Risks and uncertainties

our ability to successfully implement our strategic initiatives

whether our strategic initiatives will yield the expected benefits

the operating performance of our pipeline and energy assets

amount of capacity sold and rates achieved in our pipelines business

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regulatory decisions and outcomes

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performance of our counterparties

changes in the political environment

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interest and foreign exchange rates

weather

cyber security

technological developments

economic conditions in North America as well as globally.

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

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

TransCanada Corporation

CORPORATE STRUCTURE

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

INTERCORPORATE RELATIONSHIPS

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

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

General development of the business

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

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

DEVELOPMENTS IN THE NATURAL GAS PIPELINES BUSINESS

Canadian Pipelines

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

	transportation services that will utilize the North Montney project facilities.
August 2013	We reached settlement of the NGTL System annual revenue requirement for the years 2013 and 2014 with shippers and other interested parties (the **NGTL 2013-2014 Settlement**). The settlement fixed the return at 10.1 per cent on a 40 per cent deemed common equity, established an increase in the composite depreciation rate to 3.05 per cent and 3.12 per cent for 2013 and 2014, respectively, and fixed the OM&A costs for 2013 at $190 million and 2014 at $198 million with any variance to our account. We also requested and received approval for changes to existing interim rates to reflect the settlement, effective September 1, 2013, pending a decision on the settlement application.
November 2013	We filed an application with the NEB to construct and operate the North Montney project. The estimated capital cost of the project is $1.7 billion and it consists of approximately 300 km (186 mile) of pipeline.
November 2013	The NEB approved the NGTL 2013-2014 Settlement and final 2013 rates, as filed, in November 2013. We expect the final tolls for 2014 for the NGTL System will be determined on the basis of the NGTL settlement process.

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

	LDC Settlement will enable the addition of facilities in the Eastern Triangle to serve immediate market demand for supply diversity and market access. The LDC Settlement is intended to provide a market driven, stable, long-term accommodation of future demand in this region in combination with the anticipated lower demand for transportation on the Prairies Line and the Northern Ontario Line while providing a reasonable opportunity to recover our costs. The LDC Settlement also retains pricing flexibility for discretionary services and implements certain tariff changes and new services as required by the terms of the settlement. The NEB decision remains in effect pending the outcome of the LDC Settlement application.
January 2014	Shippers on the Canadian Mainline elected to renew approximately 2.5 Bcf/d of their contracts through November 2016. This represents a significant amount of volume renewal, especially by Canadian shippers.

Date	Description of development
U.S. Pipelines	
Gas Transmission Northwest LLC (GTN)	
May 2011	We closed the sale of a 25 per cent interest in each of GTN and Bison Pipeline LLC (**Bison**) to TC PipeLines, LP (**TCLP**) for a total transaction value of US$605 million, which included US$81 million or 25 percent of GTN's outstanding debt.
November 2011	The Federal Energy Regulatory Commission (**FERC**) approved a settlement agreement between GTN and its shippers for new transportation rates to be effective January 2012 through December 2015. This settlement also requires GTN to file for new rates that are to be effective January 2016.
July 2013	We sold an additional 45 per cent interest in each of GTN and Bison to TCLP for an aggregate purchase price of US$1.05 billion. We continue to hold a 30 per cent direct ownership interest in both pipelines. We also hold a 28.9 per cent interest in and are the General Partner of, TCLP.
Bison	
January 2011	Bison pipeline was placed into commercial service.
May 2011	We closed the sale of a 25 per cent interest in each of GTN and Bison to TCLP for a total transaction value of US$605 million, which included US$81 million or 25 percent of GTN's outstanding debt.
July 2013	We sold an additional 45 per cent interest in each of GTN and Bison to TCLP for an aggregate purchase price of US$1.05 billion. We continue to hold a 30 per cent direct ownership interest in both pipelines. We also hold a 28.9 per cent interest in and are the General Partner of, TCLP.
Great Lakes	
November 2013	Great Lakes received FERC approval for a rate settlement with its shippers resulting in maximum recourse rates increasing by approximately 21 per cent resulting in a modest increase in revenues derived from its recourse rate contracts. The settlement includes a 17 month moratorium through March 2015 and requires us to have new rates in effect by January 1, 2018.
Northern Border	
January 2013	Northern Border secured a final settlement agreement with its shippers that the FERC approved in December 2012, effective January 2013. The settlement rates for long haul transportation are approximately 11 per cent lower than 2012 rates and depreciation was lowered from 2.4 to 2.2 per cent. The settlement also includes a three year moratorium on filing cases or challenging the settlement rates but Northern Border must initiate another rate proceeding within five years.
ANR Pipeline	
June 2012	The FERC issued orders approving ANR's sale of its offshore assets to a newly created wholly owned subsidiary, TC Offshore LLC (**the LLC**), allowing the LLC to operate these assets as a stand alone interstate pipeline.
August 2012	The FERC approved ANR Storage Company's settlement with its shippers.
November 2012	The LLC began commercial operations.

ANR Lebanon Lateral Reversal Project

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

Mexican Pipelines

Topolobampo and Mazatlan Pipeline projects

November 2012	The CFE awarded us with the contract to build, own and operate the Topolobampo pipeline project. The Topolobampo project is a 530 km (329 mile), 30 inch pipeline with a capacity of 670 MMcf/d and an estimated cost of US$1 billion that will deliver gas from El Encino, Chihuahua and interconnects with third party pipelines in El Oro, Sinaloa to Topolobampo, Sinaloa.
November 2012	The CFE awarded us with the contract to build, own and operate the Mazatlan pipeline project, from El Oro to Mazatlan, Mexico. The Mazatlan project is a 413 km (257 mile), 24 inch pipeline running from El Oro to Mazatlan, within the state of Sinaloa with a capacity of 200 MMcf/d and an estimated cost of US$400 million.
First Quarter 2014	Permitting and engineering activities are advancing as planned for these two northwest Mexico pipelines. Both projects are supported by 25 year contracts with the CFE and are expected to be in service mid to late 2016.

Date	Description of development
Tamazunchale Pipeline Extension project	
February 2012	We signed a contract with the CFE for the Tamazunchale Pipeline Extension project. Engineering, procurement and construction contracts were signed and construction related activities began.
First Quarter 2014	The construction of the US$500 million Tamazunchale Pipeline Extension project is proceeding although delays have occurred due to a significant number of archeological finds within the pipeline route. It is expected these findings and related alternative construction will move the project's scheduled in service date to second quarter 2014. As these types of findings are not uncommon in significant infrastructure projects in Mexico, contractual relief for such delays is provided. We continue to work with local, state and federal authorities to minimize and mitigate ground disturbance at the specific sites as well as to minimize impact to the scheduled in service date.
Guadalajara	
June 2011	The Guadalajara pipeline was completed. We and CFE agreed to add a US$60 million compressor station to the pipeline.
First Quarter 2013	The compressor station went into service.
LNG Pipeline Projects	
Coastal GasLink	
June 2012	We were selected to design, build, own and operate the proposed Coastal GasLink project. The estimated $4 billion, 650km (404 mile) pipeline is expected to have an initial capacity of 1.7 Bcf/d and will transport natural gas from the Montney gas producing region near Dawson Creek, B.C. to LNG Canada's proposed LNG export facility near Kitimat, B.C.
January 2014	We filed the Application for an Environmental Assessment Certificate with the B.C. Environmental Assessment Office (**BCEAO**). We are currently focused on community, landowner, government and First Nations engagement as the project advances through the regulatory process. The pipeline would be placed in service near the end of the decade, subject to a final investment decision to be made by LNG Canada after obtaining final regulatory approvals. We continue to advance this project and all costs would be recoverable should the project not proceed.
Prince Rupert Gas Transmission Project (PRGT)	
January 2013	We were selected to design, build, own and operate the proposed $5 billion, 750 km (466 mile) PRGT. The proposed pipeline will transport natural gas primarily from the North Montney gas-producing region near Fort St John, B.C. to the proposed Pacific Northwest LNG export facility near Prince Rupert, B.C. We are currently focused on First Nations, community, landowner and government engagement as the PRGT advances through the regulatory process with the BCEAO. We continue to refine our study corridor based on consultation and detailed studies to date. A final investment decision to construct the project, for a planned in service date of late 2018, is expected to be made following final regulatory approvals. We continue to advance this project and all costs would be fully recoverable should the project not proceed.
Alaska LNG Project	
March 2012	Three major producers (the **Alaska North Slope producers**), along with us through participation in the Alaska LNG Project, announced the companies have agreed on a work plan aimed at commercializing North Slope natural gas resources through an LNG option. This would involve construction of a natural gas pipeline from the North Slope to Valdez, Alaska where the gas would be liquefied and shipped to international markets.

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

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

DEVELOPMENTS IN THE OIL PIPELINES BUSINESS

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

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

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

	We announced we had reached binding long-term shipping agreements to build, own and operate the Heartland Pipeline and TC Terminals projects, and filed a permit application for the terminal facility. The projects will include a 200 km (125 mile) crude oil pipeline connecting the Edmonton/Heartland, Alberta market to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton, Alberta. We anticipate the pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined cost estimated at $900 million and are expected to be placed in service in 2016.
October 2013	We filed a permit application for the pipeline with the AER after completing the required Aboriginal and stakeholder engagement and associated field work.
February 2014	The application for the terminal facility was approved.
Keystone Hardisty Terminal	
March 2012	We launched and concluded a binding open season to obtain commitments from interested parties for the Keystone Hardisty Terminal.
May 2012	We announced that we had secured binding long-term commitments of more than 500,000 Bbl/d for the Keystone Hardisty Terminal, and are expanding the proposed two million barrel project to a 2.6 million barrel terminal at Hardisty, Alberta, due to strong commercial support.
May 2013	We started construction on the Keystone Hardisty Terminal which we anticipate will have a storage capacity of up to 2.6 million barrels of crude oil. The $300 million crude oil terminal at Hardisty, Alberta is expected to be in service in 2016.

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

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

DEVELOPMENTS IN THE ENERGY BUSINESS

Date	Description of development
Ontario Solar	
December 2011	We agreed to buy nine Ontario solar generation facilities (combined capacity of 86 megawatt (**MW**)) from Canadian Solar Solutions Inc. (**Canadian Solar**), for approximately $500 million. Under the terms of the agreement, Canadian Solar will develop and build each of the nine solar facilities using photovoltaic panels. We buy each facility once construction and acceptance testing are complete and commercial operation begins. All power produced by the solar facilities is currently or will be sold under 20 year PPAs with the OPA.
June 2013	We completed the acquisition of the first facility for $55 million.
September 2013	We completed the acquisition of two solar facilities for $99 million.
December 2013	We completed the acquisition of a fourth solar facility for $62 million. We expect the acquisition of the remaining five facilities to close in 2014, subject to satisfactory completion of the related construction activities and regulatory approvals.
Cancarb Limited and Cancarb Waste Heat Facility	
January 2014	We announced we had reached an agreement for the sale of Cancarb Limited, our thermal carbon black facility, and its related power generation facility for $190 million subject to closing adjustments. The sale is expected to close in late first quarter 2014.
Bécancour	
June 2011	Hydro-Québec Distribution (**Hydro-Québec**) notified us it would exercise its option to extend the agreement to suspend all electricity generation from Bécancour throughout 2012. Under the original agreement, Hydro-Québec had the option to extend the suspension on an annual basis until such time as regional electricity demand levels recover.
June 2012	Hydro-Québec notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2013.
June 2013	Hydro-Québec notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2014.
December 2013	We entered into an amendment to the original suspension agreement with Hydro-Québec to further extend suspension of generation through to the end of 2017. Under the amendment, Hydro-Québec continues to have the option (subject to certain conditions) to further extend the suspension past 2017. The amendment also includes revised provisions intended to reduce Hydro-Québec's payments to us for Bécancour's natural gas transportation costs during the suspension period, although we retain our ability to recover our full capacity costs under the Electricity Supply Contract with Hydro-Québec while the facility is suspended. Final execution of this amendment is conditional on the pending approval by the Régie de l'énergie.
Sundance	
January 2011	The Sundance A Units 1 and 2 were subject to a force majeure claim by the operator.
February 2011	The operator informed us that it was not economic to replace or repair Sundance A Units 1 and 2, and that the Sundance A PPA should be terminated. We disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA. Throughout 2011, revenues and costs had been

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

Date	**Description of development**
Bruce Power	
February 2011	The Bruce Power Refurbishment Implementation Agreement (the **BPRIA**) was amended to extend the suspension date for Bruce A contingent support payments from December 31, 2011 to June 1, 2012. Contingent support payments received from the OPA by Bruce A are equal to the difference between the fixed prices under the BPRIA and spot market prices. As a result of the amendment, all output from Bruce A was subject to spot prices effective June 1, 2012 until the restart of both Units 1 and 2 was complete. Bruce Power and the OPA had amended certain terms and conditions of the BPRIA in July 2009, which included: amendments to the Bruce B floor price mechanism, the removal of a support payment cap for Bruce A, an amendment to the capital cost-sharing mechanism, and addition of a provision for deemed generation payments to Bruce Power at the contracted prices under circumstances where generation from Bruce A and Bruce B is reduced due to system curtailments on the Independent Electricity System Operator controlled grid in Ontario. Under the original BPRIA, which was signed in 2005, Bruce A committed to refurbish and restart the then currently idle Units 1 and 2, extend the operating life of Unit 3 and replace the steam generators on Unit 4. Fuelling of both Unit 2 and Unit 1 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012.
November 2011	Bruce Power commenced the West Shift Plus outage as part of the life extension strategy for Unit 3.
March 2012	Bruce Power received authorization from the Canadian Nuclear Safety Commission to power up the Unit 2 reactor.
May 2012	An incident occurred within the Unit 2 electrical generator on the non-nuclear side of the plant which delayed the synchronization of Unit 2 to the Ontario electrical grid. As a result, Bruce Power submitted a force majeure claim to the OPA.
June 2012	Bruce Power returned Unit 3 to service after completing the $300 million West Shift Plus life extension outage, which began in 2011. Unit 4 was expected to return to service in late first quarter 2013 after the completion of an expanded outage investment program that began in August 2012. These investments should allow Units 3 and 4 to produce low cost electricity until at least 2021.
August 2012	We confirmed that Bruce Power's force majeure claim to the OPA related to Unit 2 (**Bruce A**) had been accepted. The claim was the result of a May 2012 event that delayed the synchronization of this unit to the Ontario power grid. With the acceptance of the force majeure claim, Bruce Power continued to receive the contracted price for power generated from the operating units at Bruce A after July 1, 2012.
October 2012	Unit 1 and 2 were returned to service following the completion of the refurbishment. The incident in May 2012 within the Unit 2 electrical generator on the non-nuclear side of the plant had delayed returning the units to service. Bruce Power's force majeure claim to the OPA was accepted in August, and it continued to receive the contracted price for power generated during the force majeure period.
November 2012	Both Units 1 and 2 have operated at reduced output levels following their return to service, and Bruce Power took Unit 1 offline for an approximate one month maintenance outage. Bruce Power expects the availability percentages for Units 1 and 2 to increase over time, however, these units have not operated for an extended period of time and may experience slightly higher forced outage rates and reduced availability percentages in 2013. All that time, overall plant availability for Bruce A was expected to be approximately 90 per cent in 2013.
April 2013	Bruce Power announced that it had reached an agreement with the OPA to extend the Bruce B floor price through to the end of the decade, which is expected to coincide with the 2019 and 2020 end of life dates for the Bruce B units.
April 2013	Bruce Power returned Bruce A Unit 4 to service after completing an expanded life extension outage investment program, which began in August 2012. It is anticipated that this investment will allow Unit 4 to operate until at least 2021.

January 2014	Cameco Corporation announced it had agreed to sell its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust. We are considering our option to increase our Bruce B ownership percentage.
Napanee	
December 2012	We signed a contract with the OPA to develop, own and operate a new 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. Currently, the project is on schedule and we expect to complete the permitting process in late 2014. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late 2017 or early 2018.
Cartier Wind	
November 2011	The Montagne-Sèche project and phase one of the Gros-Morne wind farm were completed.
November 2012	We placed the second phase of the Gros-Morne wind farm project in service, completing the 590 MW, five phase Cartier Wind Project in Québec. All of the power produced by Cartier Wind is sold to Hydro-Québec under 20 year PPAs.

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

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

Business of TransCanada

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

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

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

(2)

Revenues include sales of natural gas.

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

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

NATURAL GAS PIPELINES BUSINESS

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

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

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

		U.S. upper Midwest. We effectively own 67 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28.9 per cent interest in TCLP	
Iroquois	666 km (414 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. northeast	44.5%
North Baja	138 km (86 miles)	Transports natural gas between Arizona and California, and connects with another third-party system on the California/Mexico border. We effectively own 28.9 per cent of the system through our interest in TCLP	28.9%
Northern Border	2,265 km (1,407 miles)	Transports natural gas through the U.S. Midwest, and connects with Foothills near Monchy, Saskatchewan. We effectively own 14.5 per cent of the system through our 28.9 per cent interest in TCLP	14.5%
Portland	474 km (295 miles)	Connects with TQM near East Hereford, Québec, to deliver natural gas to customers in the U.S. northeast	61.7%
Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to Nevada, and delivers gas in northeastern California and northwestern Nevada. We effectively own 28.9 per cent of the system through our interest in TCLP	28.9%

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

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

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

OIL PIPELINES BUSINESS

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

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

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

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

REGULATION OF THE NATURAL GAS AND OIL PIPELINES BUSINESSES

Canada

Natural Gas Pipelines

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

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

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

Natural Gas Pipelines Projects

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

Oil Pipelines

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

Oil Pipelines Projects

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

United States

Natural Gas Pipelines

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

Oil Pipelines

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

Mexico

Natural Gas Pipelines

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

ENERGY BUSINESS

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

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

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

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

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

	Generating capacity (MW)	Type of fuel	Description	Location	Ownership
Canadian Power 8,070 MW of power generation capacity (including facilities in development)					
Western Power 2,636 MW of power supply in Alberta and the western U.S.					
Bear Creek	80	natural gas	Cogeneration plant	Grand Prairie, Alberta	100%
Cancarb[1]	27	natural gas, waste heat	Facility fuelled by waste heat from an adjacent TransCanada facility that produces thermal carbon black, a by-product of natural gas	Medicine Hat, Alberta	100%
Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
Coolidge[2]	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
Sheerness PPA	756	coal	PPA for entire output of facility	Hanna, Alberta	100%
Sundance A PPA	560	coal	PPA for entire output of facility	Wabamun, Alberta	100%
Sundance B PPA (Owned by ASTC[3])	353[3]	coal	PPA for entire output of facility	Wabamun, Alberta	50%
Eastern Power 2,950 MW of power generation capacity (including facilities in development)					

Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
Cartier Wind	366[4]	wind	Five wind power projects	Gaspésie, Québec	62%
Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
Portlands Energy	275[4]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
Ontario Solar	36	solar	Four solar facilities	Southern Ontario	100%

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

(1)

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

(2)

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

(3)

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

(4)

Our share of power generation capacity.

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

Power purchased under long-term contracts is as follows:

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

Power sold under long-term contracts is as follows:

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

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

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

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

(1)
Power generation has been suspended since 2008.

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

Assets currently in development are as follows:

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

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

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

General

EMPLOYEES

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

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

HEALTH, SAFETY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

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

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

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

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

Environmental policies

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

Safety and asset integrity

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

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

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

Social Policies

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

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

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

Risk factors

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

Dividends

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

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

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

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

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

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

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

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

(1) Issued March 4, 2013.

(2) Issued January 20, 2014.

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

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

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

Description of capital structure

SHARE CAPITAL

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

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

(1) Issued January 20, 2014.

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

Common shares

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

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

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

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

First preferred shares

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

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

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

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

The Series 1 preferred shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The Series 1 preferred shares are redeemable by TransCanada in whole or in part on December 31, 2014, and on December 31 in every fifth year thereafter, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 1 preferred shares have the right to convert their shares into cumulative redeemable Series 2 preferred shares, subject to certain conditions, on December 31, 2014 and on December 31 in every fifth year thereafter. The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90 day Government of Canada treasury bill rate and 1.92 per cent and have the right to convert their shares into Series 1 preferred shares, subject to certain conditions, on December 31, 2019 and on December 31 in every fifth year thereafter. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 1

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

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

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

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

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

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

Second preferred shares

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

Credit ratings

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

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

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

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

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

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

DBRS

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

MOODY'S

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

S&P

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

Market for securities

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

COMMON SHARES

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

January 2013	$49.44	$46.82	$47.21	26,082,774	$49.64	$47.16	$47.37	11,080,878

SERIES 1 PREFERRED SHARES

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

SERIES 3 PREFERRED SHARES

	TSX (TRP.PR.B)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**
December 2013	$20.63	$20.03	$20.37	998,882
November 2013	$21.16	$19.98	$20.68	517,633
October 2013	$20.64	$19.94	$20.03	290,469
September 2013	$22.09	$19.91	$20.14	922,863

August 2013	$22.96	$20.27	$21.72	312,075
July 2013	$23.94	$22.81	$22.86	349,059
June 2013	$24.90	$22.60	$23.19	263,285
May 2013	$24.97	$24.55	$24.76	448,999
April 2013	$24.90	$24.37	$24.65	571,040
March 2013	$25.04	$24.32	$24.93	508,121
February 2013	$24.90	$24.34	$24.56	621,184
January 2013	$25.00	$24.39	$24.80	555,279

SERIES 5 PREFERRED SHARES

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

SERIES 7 PREFERRED SHARES

	TSX (TRP.PR.D)			
Month	High ($)	Low ($)	Close ($)	Volume Traded
December 2013	$25.50	$25.00	$25.11	686,593
November 2013	$25.48	$24.50	$25.45	528,477
October 2013	$25.12	$24.50	$25.05	765,889
September 2013	$25.05	$23.85	$24.84	383,697
August 2013	$25.12	$23.80	$24.87	478,375
July 2013	$25.61	$24.95	$25.18	639,196

June 2013	$25.87	$24.72	$25.16	912,786
May 2013	$26.10	$25.70	$25.75	640,573
April 2013	$26.15	$25.82	$26.00	1,990,847
March 2013	$26.15	$25.25	$26.00	3,292,039

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

SERIES U PREFERRED SHARES AND SERIES Y PREFERRED SHARES

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

Directors and officers

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

DIRECTORS

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

Name and place of residence	Principal occupation during the five preceding years	Director since
		2005

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

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

(1)

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

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

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

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

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

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

BOARD COMMITTEES

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

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

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

OFFICERS

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

Executive officers

Name	Present position held	Principal occupation during the five preceding years
Russell K. Girling	President and Chief Executive Officer	Prior to July 2010, Chief Operating Officer since July 2009 and President, Pipelines since June 2006.
Wendy L. Hanrahan	Executive Vice-President, Corporate Services	Prior to May 2011, Vice-President, Human Resources since January 2005.
Karl R. Johannson	Executive Vice-President	Prior to November 2012, Senior Vice-President,

	and President, Natural Gas Pipelines	Canadian and Eastern U.S. Pipelines, Prior to January 2011. Senior Vice-President, Power Commercial since January 2006.
Gregory A. Lohnes(1)	Executive Vice-President, Operations and Major Projects	Prior to November 2012, Executive Vice-President and President, Natural Gas Pipelines. Prior to July 2010, Executive Vice-President and Chief Financial Officer since June 2006.
Donald R. Marchand	Executive Vice-President and Chief Financial Officer	Prior to July 2010, Vice-President, Finance and Treasurer since September 1999.
Dennis J. McConaghy(2)	Executive Vice-President, Corporate Development	Prior to July 2010, Executive Vice-President, Pipeline Strategy and Development since May 2006.
Sean McMaster(1)	Executive Vice-President, Stakeholder Relations and General Counsel and Chief Compliance Officer	Prior to February 2012, Executive Vice-President, Corporate and General Counsel since January 2007 and Chief Compliance Officer since July 2006.
Alexander J. Pourbaix	President, Energy and Oil Pipelines	Prior to July 2010, Executive Vice-President, Corporate Development since July 2009 and President, Energy since June 2006.

(1)
Retiring effective February 28, 2014.

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

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

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

William C. Taylor	Executive Vice-President and President, Energy	Prior to March 2014, Senior Vice-President, US and Canadian Power. Prior to May 2013, Senior Vice-President, Eastern Power. Prior to July 2010, Vice-President and General Manager, U.S. Northeast Power since May 2008 (TCPL).

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

Corporate officers

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

CONFLICTS OF INTEREST

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

Serving on other boards

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

shipper. The Governance committee monitors relationships among directors to ensure that business associations do not affect the Board's performance.

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

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

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

Affiliates

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

Corporate governance

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

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

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

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

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

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

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

Audit committee

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

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS

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

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

Kevin E. Benson

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

Derek H. Burney

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

Mary Pat Salomone

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

D. Michael G. Stewart

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

Richard E. Waugh

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

PRE-APPROVAL POLICIES AND PROCEDURES

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

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

EXTERNAL AUDITOR SERVICE FEES

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

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

Legal proceedings and regulatory actions

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

Transfer agent and registrar

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

Interest of experts

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

Additional information

1. Additional information in relation to TransCanada may be found under TransCanada's profile on SEDAR (www.sedar.com).

2. Additional information including directors' and officers' remuneration and indebtedness, principal holders of TransCanada's securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TransCanada's

management information circular for its most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from the Corporate Secretary of TransCanada.

3. Additional financial information is provided in TransCanada's audited consolidated financial statements and MD&A for its most recently completed financial year.

Glossary

Units of measure

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

General terms and terms related to our operations

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

Accounting terms

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

Government and regulatory bodies terms

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

Schedule A
Metric conversion table

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

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

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

Schedule B
Charter of the Audit Committee

1. PURPOSE

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

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

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

2. ROLES AND RESPONSIBILITIES

I. Appointment of the Company's External Auditors

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

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

II. Oversight in Respect of Financial Disclosure

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III. Oversight in Respect of Legal and Regulatory Matters

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

IV. Oversight in Respect of Internal Audit

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

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

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

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

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

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

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

(iii) the internal audit department responsibilities, budget and staffing;

and to report to the Board on such meetings;

V. Insight in Respect of the External Auditors

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

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

(c)
meet separately with the external auditors to review with them any problems or difficulties the external auditors may have encountered and specifically:
(i)
any difficulties which were encountered in the course of the audit work, including any restrictions on the scope of activities or access to required information, and any disagreements with management;
(ii)
any changes required in the planned scope of the audit;

and to report to the Board on such meetings;

(d)
meet with the external auditors prior to the audit to review the planning and staffing of the audit;
(e)
receive and review annually the external auditors' written report on their own internal quality control procedures; any material issues raised by the most recent internal quality control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, and any steps taken to deal with such issues;
(f)
review and evaluate the external auditors, including the lead partner of the external auditor team;
(g)
ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law, but at least every five years;

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

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

VII. Oversight in Respect of Certain Policies

(a)
review and recommend to the Board for approval the implementation and amendments to policies and program initiatives deemed advisable by management or the Audit Committee with respect to the Company's codes of business ethics and Risk Management and Financial Reporting policies;
(b)
obtain reports from management, the Company's senior internal auditing executive and the external auditors and report to the Board on the status and adequacy of the Company's efforts to ensure its businesses are conducted and its facilities are operated in an ethical, legally compliant and socially responsible manner, in accordance with the Company's codes of business conduct and ethics;
(c)

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

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

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

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

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

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

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

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

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

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

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

(h) approve the appointment or termination of auditors;

IX. U.S. Stock Plans

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

X. Oversight in Respect of Internal Administration

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

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

XI. Information Security

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

XII. Oversight Function

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

3. COMPOSITION OF AUDIT COMMITTEE

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

4. APPOINTMENT OF AUDIT COMMITTEE MEMBERS

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

5. VACANCIES

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

6. AUDIT COMMITTEE CHAIR

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

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

(b) preside over meetings of the Audit Committee;

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

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

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

7. ABSENCE OF AUDIT COMMITTEE CHAIR

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

8. SECRETARY OF AUDIT COMMITTEE

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

9. MEETINGS

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

10. QUORUM

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

11. NOTICE OF MEETINGS

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

12. ATTENDANCE OF COMPANY OFFICERS AND EMPLOYEES AT MEETING

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

13. PROCEDURE, RECORDS AND REPORTING

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

14. REVIEW OF CHARTER AND EVALUATION OF AUDIT COMMITTEE

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

15. OUTSIDE EXPERTS AND ADVISORS

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

16. RELIANCE

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

Management's discussion and analysis

February 19, 2014

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2013.

This MD&A should be read with our accompanying December 31, 2013 audited comparative consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. generally accepted accounting principles (GAAP).

Contents

About this document

Throughout this MD&A, the terms, *we*, *us*, *our* and *TransCanada* mean TransCanada Corporation and its subsidiaries.

Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 96.

All information is as of February 19, 2014 and all amounts are in Canadian dollars, unless noted otherwise.

FORWARD-LOOKING INFORMATION

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

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

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

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

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

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

Assumptions

inflation rates, commodity prices and capacity prices

timing of financings and hedging

regulatory decisions and outcomes

foreign exchange rates

interest rates

tax rates

planned and unplanned outages and the use of our pipeline and energy assets

integrity and reliability of our assets

access to capital markets

anticipated construction costs, schedules and completion dates

acquisitions and divestitures.

Risks and uncertainties

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

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

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

FOR MORE INFORMATION

See Supplementary information beginning on page 165 for other consolidated financial information on TransCanada for the last three years.

You can also find more information about TransCanada in our annual information form and other disclosure documents, which are available on SEDAR (www.sedar.com).

About our business

With over 60 years of experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and natural gas storage facilities.

THREE CORE BUSINESSES

We operate our business in three segments Natural Gas Pipelines, Oil Pipelines and Energy. We also have a non-operational corporate segment consisting of corporate and administrative functions that provide support and governance to our operational business segments.

Our $54 billion portfolio of energy infrastructure assets meets the needs of people who rely on us to deliver their energy safely and reliably every day. We operate in seven Canadian provinces, 31 U.S. states, Mexico and three South American countries.

at December 31 (millions of $)	2013	2012	per cent change
Total assets			
Natural Gas Pipelines	**25,165**	23,210	8%
Oil Pipelines	**13,253**	10,485	26%
Energy	**13,747**	13,157	4%
Corporate	**1,733**	1,544	12%
	53,898	48,396	11%

year ended December 31 (millions of $)	2013	2012	per cent change
Total revenue			
Natural Gas Pipelines	**4,497**	4,264	5%
Oil Pipelines	**1,124**	1,039	8%
Energy	**3,176**	2,704	17%
	8,797	8,007	10%

year ended December 31	2013	2012	per cent change

(millions of $)

Comparable EBIT 1			
Natural Gas Pipelines	**1,839**	1,808	2%
Oil Pipelines	**603**	553	9%
Energy	**1,069**	620	72%
Corporate	**(124)**	(111)	12%
	3,387	2,870	18%

1 Comparable EBIT is a non-GAAP measure see page 15 for details.

Share price of our common shares
at December 31

Common shares outstanding average

(millions)

2013	707
2012	705
2011	702

as at February 14, 2014	
Common shares	**Issued and outstanding**

	707 million

Preferred shares	Issued and outstanding	Convertible to
Series 1	22 million	22 million Series 2 preferred shares
Series 3	14 million	14 million Series 4 preferred shares
Series 5	14 million	14 million Series 6 preferred shares
Series 7	24 million	24 million Series 8 preferred shares
Series 9	18 million	18 million Series 10 preferred shares

Options to buy common shares	Outstanding	Exercisable
	7 million	4 million

A LONG-TERM STRATEGY

Our energy infrastructure business is made up of pipeline and power generation assets that gather, transport, produce, store or deliver natural gas, crude oil and other petroleum products and electricity to support businesses and communities in North America.

TransCanada's vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where we have or can develop a significant competitive advantage.

Key components of our strategy

1 Maximize the full-life value of our infrastructure assets and commercial positions

Our strategy at a glance

Long-life infrastructure assets and long-term commercial arrangements are the cornerstones of our low-risk business model.

Our pipeline assets include large-scale natural gas and crude oil pipelines that connect long-life supply basins with stable and growing markets, generating predictable and sustainable cash flows and earnings.

In Energy, long-term power sale agreements and shorter-term power sales to wholesale and load customers are used to manage and optimize our portfolio and to manage price volatility.

2 Commercially develop and build new asset investment programs

Our strategy at a glance

We are developing high quality, long-life projects under our current $38 billion capital program. These will contribute incremental earnings as our investments are placed in service.

Our expertise in managing construction risks and maximizing capital productivity ensures a disciplined approach to quality, cost and schedule, resulting in superior service for our customers and returns to shareholders.

As part of our growth strategy, we rely on this experience and our regulatory, commercial, financial, legal and operational expertise to successfully build and integrate new energy and pipeline facilities.

Our growing investment in natural gas, nuclear, wind, hydro and solar generating facilities demonstrates our commitment to clean, sustainable energy.

3 Cultivate a focused portfolio of high quality development options

Our strategy at a glance

We focus on pipelines and energy growth initiatives in core regions of North America.

We assess opportunities to acquire and develop energy infrastructure that complements our existing portfolio and provides access to attractive supply and market regions.

We will advance selected opportunities to full development and construction when market conditions are appropriate and project risks and returns are acceptable.

4 Maximize our competitive strengths

Our strategy at a glance

We are continually developing competitive strengths in areas that directly drive long-term shareholder value.

A competitive advantage

Years of experience in the energy infrastructure business and a disciplined approach to project and operational management and capital investment give us our competitive edge.

Strong leadership: scale, presence, operating capabilities, strategy development; expertise in regulatory, legal, commercial and financing support.

High quality portfolio: a low-risk business model that maximizes the full-life value of our long-life assets and commercial positions.

Disciplined operations: highly skilled in designing, building and operating energy infrastructure; focus on operational excellence; and a commitment to health, safety and the environment are paramount parts of our core values.

Financial expertise: excellent reputation for consistent financial performance and long-term financial stability and profitability; disciplined approach to capital investment; ability to access sizable amounts of competitively priced capital to support our growth.

Long-term relationships: long-term, transparent relationships with key customers and stakeholders; clear communication of our value to equity and debt investors both the upside and the risks to build trust and support.

$38 billion capital program

We are developing quality projects under our long-term $38 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties and are expected to generate significant growth in earnings and cashflow.

Our $38 billion capital program is comprised of $12 billion of small to medium-sized projects and $26 billion of large scale projects. Amounts presented exclude the impact of foreign exchange and capitalized interest.

at December 31, 2013 (billions of $)	**Expected In-Service Date**	**Estimated Project Cost**	**Amount Spent**
Small to medium-sized projects			
Gulf Coast Project[1]	January 2014	US 2.6	US 2.3
Ontario Solar	2014	0.5	0.2
Tamazunchale Extension	2014	US 0.5	US 0.4
Houston Lateral and Terminal	2015	US 0.4	US 0.1
Heartland and TC Terminals	2016	0.9	-
Keystone Hardisty Terminal	2016	0.3	0.1
Topolobampo	2016	US 1.0	US 0.4
Mazatlan	2016	US 0.4	US 0.1
Grand Rapids[2]	2015-2017	1.5	0.1
Northern Courier	2017	0.8	0.1
NGTL System	2014-2018	2.0	0.2
Napanee	2017 or 2018	1.0	-
		11.9	4.0
Large scale projects[3]			
Keystone XL[4]	Approximately 2 years from date permit received	US 5.4	US 2.2
Energy East[5]	2018	12.0	0.2
Prince Rupert Gas Transmission	2018	5.0	0.1
Coastal GasLink	2018+	4.0	0.1
		26.4	2.6
		38.3	6.6

1 Commercial in-service date of January 22, 2014.

2 Represents our 50 per cent share.

3 Subject to cost adjustments due to market conditions, route refinement, permitting conditions and scheduling.

4 Estimated project cost will increase depending on the timing of the Presidential permit.

5 Excludes transfer of Canadian Mainline gas assets.

2013 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under GAAP because we believe they improve our ability to compare results between reporting periods, and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be comparable to similar measures provided by other companies.

Highlights

Comparable EBITDA (comparable earnings before interest, taxes, depreciation and amortization), comparable EBIT (comparable earnings before interest and taxes), comparable earnings, comparable earnings per common share and funds generated from operations are all non-GAAP measures. See page 15 for more information about the non-GAAP measures we use and a reconciliation to their GAAP equivalents.

year ended December 31 (millions of $, except per share amounts)	**2013**	**2012**	**2011**
Revenue	**8,797**	8,007	7,839
Comparable EBITDA	**4,859**	4,245	4,544
Net income attributable to common shares	**1,712**	1,299	1,526
per common share basic and diluted	**$2.42**	$1.84	$2.17
Comparable earnings	**1,584**	1,330	1,559
per common share	**$2.24**	$1.89	$2.22
Operating cash flow			
Funds generated from operations	**4,000**	3,284	3,451
(Increase)/decrease in working capital	**(326)**	287	235
Net cash provided by operations	**3,674**	3,571	3,686
Investing activities			
Capital expenditures	**4,461**	2,595	2,513
Equity investments	**163**	652	633
Acquisitions, net of cash acquired	**216**	214	-
Balance sheet			
Total assets	**53,898**	48,396	47,338
Long-term debt	**22,865**	18,913	18,659
Junior subordinated notes	**1,063**	994	1,016
Preferred shares	**1,813**	1,224	1,224
Common shareholders' equity	**16,712**	15,687	15,570
Dividends declared			
per common share	**$1.84**	$1.76	$1.68
per Series 1 preferred share	**$1.15**	$1.15	$1.15
per Series 3 preferred share	**$1.00**	$1.00	$1.00
per Series 5 preferred share	**$1.10**	$1.10	$1.10
per Series 7 preferred share[1]	**$0.91**	-	-

1 Issued March 4, 2013.

Comparable earnings and net income

Comparable earnings

Comparable earnings in 2013 were $254 million higher than in 2012, an increase of $0.35 per share.

The increase in comparable earnings was the result of:

- higher equity income from Bruce Power due to incremental earnings from Units 1 and 2 and lower planned outage days at Unit 4
- higher earnings from the Canadian Mainline reflecting the higher rate of return on common equity (ROE) of 11.50 per cent in 2013 compared to 8.08 per cent in 2012 due to the National Energy Board's (NEB) 2013 decision on the Canadian Restructuring Proposal (the NEB decision)
- higher earnings from U.S. Power because of higher capacity prices in New York and higher realized power prices
- higher earnings from the NGTL System reflecting a higher investment base and the impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013
- higher earnings from the Keystone Pipeline System primarily due to higher volumes
- higher earnings from Western Power because of higher purchased volumes under the power purchase arrangements (PPA).

These increases were partly offset by lower contributions from U.S. natural gas pipelines because of lower earnings at ANR and Great Lakes.

Comparable earnings in 2012 were $229 million lower than 2011, a decrease of $0.33 per share.

The decrease in comparable earnings was the result of:

- lower earnings from Western Power reflecting a full year of the Sundance A PPA force majeure
- lower equity income from Bruce Power because of increased outage days
- lower Canadian Mainline net income in 2012 which excluded incentive earnings and reflected a lower investment base
- lower earnings from Great Lakes which reflected lower revenues as a result of lower rates and uncontracted capacity
- lower earnings from ANR because of lower transportation and storage revenues, lower incidental commodity sales and higher operating costs
- lower earnings from U.S. Power due to lower realized prices, higher load serving costs and reduced water flows at the hydro facilities
- higher comparable interest expense, mainly because of new debt issuances in 2011 and 2012.

These decreases were partially offset by:

a full year of revenue from the Guadalajara pipeline

higher Keystone Pipeline System revenues primarily due to higher volumes and a full year of earnings being recorded in 2012 compared to 11 months in 2011

incremental earnings from Cartier Wind and Coolidge

higher comparable interest income and other, mainly because we realized higher gains on derivatives used to manage our exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Net income attributable to common shares

Net income attributable to common shares in 2013 was $1,712 million, a year-over-year increase of $413 million (2012 $1,299 million; 2011 $1,526 million).

Net income attributable to common shares includes comparable earnings discussed above as well as other specific items which are excluded from comparable earnings. See page 15 for explanation of specific items in non-GAAP measures. The following specific items were recognized in net income in 2011 to 2013:

- $84 million of net income recorded in 2013 related to 2012 from the NEB decision
- $25 million favourable tax adjustment in 2013 due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax
- $15 million after-tax charge ($20 million pre-tax) in 2012 related to the Sundance A PPA arbitration decision. This charge was recorded in second quarter 2012 but related to amounts originally recorded in fourth quarter 2011
- the impact of certain risk management activities each year.

Cash flow

Funds generated from operations

Funds generated from operations were 22 per cent higher this year compared to 2012 primarily for the same reasons comparable earnings were higher, as described above.

Funds used in investing

Capital expenditures

We invested $4.5 billion in capital projects this year as part of our ongoing capital program compared to $6.4 billion we expected to spend in 2013 primarily because of the delay in Keystone XL permitting. Our capital program is a key part of our strategy to optimize the value of our existing assets and develop new, complementary assets in high demand areas that are expected to generate stable, predictable earnings and cash flow for years to come.

Capital expenditures

year ended December 31 (millions of $)	**2013**	2012	2011
Natural Gas Pipelines	**1,776**	1,389	917
Oil Pipelines	**2,483**	1,145	1,204
Energy	**152**	24	384
Corporate	**50**	37	8
	4,461	2,595	2,513

Equity investments and acquisitions

In 2013, we invested $0.2 billion in our equity investments. We also spent $0.2 billion on the acquisition of four solar facilities from Canadian Solar Solutions Inc.

Balance sheet

We maintained a strong balance sheet while growing our total assets by $6.6 billion since 2011. At December 31, 2013, common equity represented 40 per cent (42 per cent in 2012) of our capital structure. See page 68 for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by four per cent to $0.48 per share for the quarter ending March 31, 2014 which equates to an annual dividend of $1.92 per share. This is the 14th consecutive year we have increased the dividend on our common shares representing a compound annual growth rate of seven per cent since 2000.

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Dividend reinvestment plan

Under our dividend reinvestment plan (DRP), eligible holders of TransCanada common or preferred shares and preferred shares of TransCanada PipeLines Limited (TCPL) can reinvest their dividends and make optional cash payments to buy TransCanada common shares.

Before April 2011, common shares purchased with reinvested cash dividends were satisfied with shares issued from treasury at a discount to the average market price in the five days before dividend payment. Beginning with the dividends declared in April 2011, common shares purchased with reinvested cash dividends are satisfied with shares acquired on the open market without discount. The increase in annual dividends paid on common shares since 2011 is, in part, the result of this change combined with the impact of increases in the annualized dividend rate between 2011 and 2013 from $1.68 to $1.84 per share.

Quarterly dividend on our common shares

$0.48 per share (for the quarter ending March 31, 2014)

Annual dividends on our preferred shares

Series 1 $1.15

Series 3 $1.00

Series 5 $1.10

Series 7 $1.00

Series 9 $1.06

Cash dividends

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Common shares	**1,285**	1,226	961
Preferred shares	**71**	55	55

Refer to the Results section in each business segment and the Financial Condition section of this MD&A for further discussion of these highlights.

OUTLOOK

Earnings

We anticipate earnings in 2014 to be higher than 2013, mainly due to the net effect of the following:

- Gulf Coast project achieving commercial in service in January 2014
- Tamazunchale Pipeline Extension which is expected to be placed in service in second quarter 2014
- expected higher realized capacity and commodity prices in New York and New England
- full year of earnings from four solar facilities acquired in 2013 as well as the additional facilities expected to be acquired in 2014
- anticipated lower Alberta power prices and lower gas storage spreads
- no earnings from Cancarb Limited and its related power generation facility after the sale which is expected to close late in first quarter 2014
- higher operating, maintenance and administration (OM&A) costs related to new growth projects.

Results from our U.S. businesses are subject to fluctuations in foreign exchange rates. These fluctuations are largely offset by our hedging activities which are recorded in our Corporate segment.

Natural Gas Pipelines

Earnings from the Natural Gas Pipelines segment in 2014 will be affected by regulatory decisions and the timing of those decisions. Earnings will also be affected by market conditions, which drive the level of demand and the rates we secure for our services. Today's North American natural gas market is characterized by strong natural gas production, low natural gas prices and low values for storage and transportation services.

For 2014, the Canadian Mainline will continue to operate under the direction of the NEB decision which included an ROE of 11.50 per cent. We also expect the NGTL System's investment base to continue to grow as new natural gas supply in northeastern B.C. and western Alberta continues to be developed which will have a positive impact on earnings in 2014.

Many of our U.S. natural gas pipelines are backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance. ANR and Great Lakes have had more commercial exposure from transportation and storage contract renewals which resulted in reduced earnings in 2012 and 2013 as transportation and storage values fell to historically low levels. ANR and GLGT are examining commercial, regulatory and operational changes to optimize their position to benefit from positive developments in supply fundamentals, particularly in the Utica/Marcellus shale areas, combined with continued growth in end use markets for natural gas. In addition, significant effort to reduce costs for our U.S. pipelines operations are underway and expected to help with the near term revenue challenges. Overall in 2014, we expect earnings from our U.S. Pipelines to be consistent with 2013.

Earnings from our Mexican pipelines are expected to be higher in 2014 compared to 2013 as a result of the Tamazunchale Pipeline Extension being placed in service in second quarter 2014. Earnings for our current operating assets are expected to be consistent with 2013 due to the long-term nature of the contracts for these pipeline systems.

Oil Pipelines

Oil Pipelines principally generate earnings by providing pipeline capacity to shippers in exchange for fixed monthly payments that are not linked to actual throughput volumes. Uncontracted capacity is offered to the market on a spot basis which provides opportunities to generate incremental earnings.

The Gulf Coast project, an extension of the Keystone Pipeline System achieved commercial in-service in January 2014 and is expected to have a positive impact on the Oil Pipelines segment earnings in 2014. Although the majority of the capacity on this extension is contracted, the actual results for 2014 will be impacted by the level and pricing of spot volumes shipped each month, which is a function of available capacity, market conditions and competitive transportation options.

Energy
The higher level of power plant outages and other supply challenges that contributed to higher than expected prices and volatility within the Alberta power market in 2013 are not anticipated to continue in 2014. The sale of Cancarb Limited and its related power generation facility, which is expected to close in late first quarter 2014, as well as lower forecasted prices are expected to result in lower earnings in Western Power in 2014.

Eastern Power earnings in 2014 are expected to be relatively consistent with 2013 with earnings from a full year of service for four solar facilities offset by lower contributions from Bécancour.

Bruce Power equity income is expected to be consistent with 2013 earnings.

U.S. Power earnings are expected to be higher in 2014 due to an increase in realized capacity prices and commodity prices partially offset by lower power marketing contribution. Commodity prices for both power and natural gas are forecasted to be higher in 2014. As well, increased competition will continue to put downward pressure on retail and wholesale marketing margins and volumes in the U.S. Power segment.

Lower summer-to-winter natural gas spreads are expected to result in lower earnings from Natural Gas Storage.

Although a significant portion of Energy's output is sold under long-term contracts, output that is sold under shorter-term forward arrangements or at spot prices will continue to be affected by fluctuations in commodity prices.

Consolidated capital expenditures, equity investments and acquisitions
We expect to spend approximately $5 billion in 2014 on new and existing capital projects, excluding Keystone XL. The amount and timing of capital spending on Keystone XL will be dependent on the decision by the U.S. Department of State (DOS) to issue a Presidential Permit. The 2014 expected capital spending relates to the NGTL System expansion, Mexican pipelines and new growth pipeline projects including Heartland, Northern Courier and Grand Rapids.

NON-GAAP MEASURES
We use the following non-GAAP measures:

- EBITDA
- EBIT
- funds generated from operations
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable depreciation and amortization
- comparable interest expense
- comparable interest income and other
- comparable income tax expense.

These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities.

EBITDA and EBIT
We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting interest and other

financial charges, income tax, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends, and includes income from equity investments. EBIT measures our earnings from ongoing operations and is a better measure of our performance and an effective tool for evaluating trends in each segment. It is calculated in the same way as EBITDA, less depreciation and amortization.

Funds generated from operations

Funds generated from operations includes net cash provided by operations before changes in operating working capital. We believe it is a better measure of our consolidated operating cashflow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period. See page 9 for a reconciliation to net cash provided by operations.

Comparable measures

We calculate the comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. These comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Comparable measure	Original measure
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
comparable EBITDA	EBITDA
comparable EBIT	EBIT
comparable depreciation and amortization	depreciation and amortization
comparable interest expense	interest expense
comparable interest income and other	interest income and other
comparable income tax expense	income tax expense/(recovery)

Our decision not to include a specific item is subjective and made after careful consideration. These may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments
- gains or losses on sales of assets
- legal and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- write-downs of assets and investments.

We calculate comparable earnings by excluding the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

Reconciliation of non-GAAP measures

year ended December 31 (millions of $, except per share amounts)	2013	2012	2011
EBITDA	**4,958**	4,224	4,495
Non-comparable risk management activities affecting EBITDA	**(44)**	21	49
NEB decision 2012	**(55)**	-	-
Comparable EBITDA	**4,859**	4,245	4,544
Comparable depreciation and amortization	**(1,472)**	(1,375)	(1,328)
Comparable EBIT	**3,387**	2,870	3,216
Other income statement items			
Comparable interest expense	**(984)**	(976)	(939)
Comparable interest income and other	**42**	86	60
Comparable income tax	**(662)**	(477)	(594)
Net income attributable to non-controlling interests	**(125)**	(118)	(129)
Preferred share dividends	**(74)**	(55)	(55)
Comparable earnings	**1,584**	1,330	1,559
Specific items (net of tax):			
NEB decision 2012	**84**	-	-
Part VI.I income tax adjustment	**25**	-	-
Sundance A PPA arbitration decision 2011	**-**	(15)	-
Risk management activities[1]	**19**	(16)	(33)
Net income attributable to common shares	**1,712**	1,299	1,526
Comparable depreciation and amortization	**(1,472)**	(1,375)	(1,328)
Specific item:			
NEB decision 2012	**(13)**	-	-
Depreciation and amortization	**(1,485)**	(1,375)	(1,328)
Comparable interest expense	**(984)**	(976)	(939)
Specific items:			
NEB decision 2012	**(1)**	-	-
Risk management activities[1]	**-**	-	2
Interest expense	**(985)**	(976)	(937)
Comparable interest income and other	**42**	86	60
Specific items:			
NEB decision 2012	**1**	-	-
Risk management activities[1]	**(9)**	(1)	(5)
Interest income and other	**34**	85	55

year ended December 31 (millions of $, except per share amounts)	**2013**	**2012**	**2011**
Comparable income tax expense	**(662)**	(477)	(594)
Specific items:			
NEB decision 2012	**42**	-	-
Part VI.I income tax adjustment	**25**	-	-
Sundance A PPA arbitration decision 2011	**-**	5	-
Risk management activities[1]	**(16)**	6	19
Income tax expense	**(611)**	(466)	(575)
Comparable earnings per common share	**$2.24**	$1.89	$2.22
Specific items (net of tax):			
NEB decision 2012	**0.12**	-	-
Part VI.I Income tax adjustment	**0.04**	-	-
Sundance A PPA arbitration decision 2011	**-**	(0.02)	-
Risk management activities[1]	**0.02**	(0.03)	(0.05)
Net income per common share	**$2.42**	$1.84	$2.17

1

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Canadian Power	**(4)**	4	1
U.S. Power	**50**	(1)	(48)
Natural Gas Storage	**(2)**	(24)	(2)
Interest rates	**-**	-	2
Foreign exchange	**(9)**	(1)	(5)
Income tax attributable to risk management activities	**(16)**	6	19
Total gains/(losses) from risk management activities	**19**	(16)	(33)

Comparable EBITDA and comparable EBIT by business segment

year ended December 31, 2013 (millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	**2,852**	**752**	**1,363**	**(108)**	**4,859**
Comparable depreciation and amortization	**(1,013)**	**(149)**	**(294)**	**(16)**	**(1,472)**

Comparable EBIT	**1,839**	**603**	**1,069**	**(124)**	**3,387**

year ended December 31, 2012 (millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	2,741	698	903	(97)	4,245
Comparable depreciation and amortization	(933)	(145)	(283)	(14)	(1,375)
Comparable EBIT	1,808	553	620	(111)	2,870

year ended December 31, 2011 (millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	2,875	587	1,168	(86)	4,544
Comparable depreciation and amortization	(923)	(130)	(261)	(14)	(1,328)
Comparable EBIT	1,952	457	907	(100)	3,216

Natural Gas Pipelines

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facilities and other businesses across Canada, the U.S. and Mexico. We serve more than 80 per cent of the Canadian demand and approximately 15 per cent of the U.S. demand on a daily basis by connecting major natural gas supply basins and markets through:

- wholly owned natural gas pipelines 57,000 km (35,500 miles)
- partially owned natural gas pipelines 11,500 km (7,000 miles).

We have regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf, making us one of the largest providers of natural gas storage and related services in North America.

Strategy at a glance

Optimizing the value of our existing natural gas pipelines systems, while responding to the changing flow patterns of natural gas in North America, is a top priority.

We are also pursuing new pipeline projects to add incremental value to our business. Our key areas of focus include:

- greenfield development opportunities, such as infrastructure for liquefied natural gas (LNG) exports from the west coast of Canada and additional pipeline developments within Mexico
- connections to emerging Canadian and U.S. shale gas and other supplies
- connections to new and growing

markets

all of which play a critical role in meeting the increasing demand for natural gas in North America.

20 -- TransCanada Corporation

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			
1	NGTL System	24,522 km (15,237 miles)	Gathers and transports natural gas within Alberta and northeastern B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines	100%
2	Canadian Mainline	14,114 km (8,770 miles)	Transports natural gas from the Alberta/Saskatchewan border to serve eastern Canada and the U.S. northeast markets	100%
3	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%
4	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			
5	Pipeline	16,121 km (10,017 miles)	Transports natural gas from producing fields in Texas and Oklahoma, from offshore and onshore regions of the Gulf of Mexico and from the U.S. midcontinent, for delivery to the Gulf Coast region as well as Wisconsin, Michigan, Illinois, Indiana and Ohio. Connects with Great Lakes	100%
5a	Storage	250 Bcf	Provides regulated underground natural gas storage service from facilities located in Michigan	
6	Bison	487 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 50.2 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.9 per cent interest in TC PipeLines, LP	50.2%
7	Gas Transmission Northwest (GTN)	2,178 km (1,353 miles)	Transports natural gas from the WCSB and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 50.2 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.9 per cent interest in TC PipeLines, LP	50.2%
8	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada, and the U.S. upper Midwest. We effectively own 67 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28.9 per cent	67%

			interest in TC PipeLines, LP	
9	Iroquois	666 km (414 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. northeast	44.5%

		length	description	effective ownership
	U.S. pipelines			
10	North Baja	138 km (86 miles)	Transports natural gas between Arizona and California, and connects with another third-party system on the California/Mexico border. We effectively own 28.9 per cent of the system through our interest in TC PipeLines, LP	28.9%
11	Northern Border	2,265 km (1,407 miles)	Transports natural gas through the U.S. Midwest, and connects with Foothills near Monchy, Saskatchewan. We effectively own 14.5 per cent of the system through our 28.9 per cent interest in TC PipeLines, LP	14.5%
12	Portland	474 km (295 miles)	Connects with TQM near East Hereford, Québec, to deliver natural gas to customers in the U.S. northeast	61.7%
13	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to Nevada, and delivers gas in northeastern California and northwestern Nevada. We effectively own 28.9 per cent of the system through our interest in TC PipeLines, LP	28.9%
	Mexican pipelines			
14	Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
15	Tamazunchale	130 km (81 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi	100%
	Under construction			
16	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%
17	Tamazunchale Pipeline Extension	235 km (146 miles)	To extend existing terminus of the Tamazunchale Pipeline to deliver natural gas to power generating facilities in El Sauz, Queretaro and other parts of central Mexico	100%
18	Topolobampo Pipeline	530 km (329 miles)	To deliver natural gas to Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico	100%
	In development			
19	Alaska LNG Pipeline	1,448 km* (900 miles)	To transport natural gas from Prudhoe Bay to LNG facilities in Nikiski, Alaska	

20	Coastal GasLink	650 km* (404 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect on NGTL near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	100%
21	Prince Rupert Gas Transmission	750 km* (466 miles)	To deliver natural gas from the North Montney gas producing region at a NGTL interconnect near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
22	North Montney Mainline	306 km* (190 miles)	To deliver natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline	100%

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

RESULTS

Natural Gas Pipelines results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Canadian Pipelines			
Canadian Mainline	**1,121**	994	1,058
NGTL System	**846**	749	742
Foothills	**114**	120	127
Other Canadian (TQM[1], Ventures LP)	**26**	29	34
Canadian Pipelines comparable EBITDA	**2,107**	1,892	1,961
Comparable depreciation and amortization	**(790)**	(715)	(711)
Canadian Pipelines comparable EBIT	**1,317**	1,177	1,250
U.S. and International Pipelines (in US$)			
ANR	**188**	254	306
GTN[2]	**76**	112	131
Great Lakes[3]	**34**	62	101
TC PipeLines, LP[1,4]	**72**	74	85
Other U.S. pipelines (Iroquois[1], Bison[2], Portland[5])	**107**	111	111
International (Gas Pacifico/INNERGY[1], Guadalajara[6], Tamazunchale, TransGas[1])	**106**	112	77
General, administrative and support costs	**(10)**	(8)	(9)
Non-controlling interests[7]	**186**	161	173
U.S. and International Pipelines comparable EBITDA	**759**	878	975
Comparable depreciation and amortization	**(217)**	(218)	(214)
U.S. and International Pipelines comparable EBIT	**542**	660	761
Foreign exchange impact	**15**	-	(7)
U.S. and International Pipelines comparable EBIT (Cdn$)	**557**	660	754
Business Development comparable EBITDA and comparable EBIT	**(35)**	(29)	(52)
Natural Gas Pipelines comparable EBIT	**1,839**	1,808	1,952
Summary			
Natural Gas Pipelines comparable EBITDA	**2,852**	2,741	2,875
Comparable depreciation and amortization	**(1,013)**	(933)	(923)
Natural Gas Pipelines comparable EBIT	**1,839**	1,808	1,952

Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments.

2

Effective July 1, 2013, reflects our direct ownership interest of 30 per cent. Prior to that our direct ownership interest was 75 per cent effective May 2011 and 100 per cent prior to that date.

3

Represents our 53.6 per cent direct ownership interest. The remaining 46.4 per cent is held by TC PipeLines, LP.

4

Effective May 22, 2013, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent. On July 1, 2013, we sold 45 per cent of GTN and Bison to TC PipeLines, LP. The following table shows our ownership interest in TC PipeLines, LP and our ownership of GTN, Bison, and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of			
	July 1, 2013	**May 22, 2013**	**May 3, 2011**	**January 1, 2011**
TC PipeLines, LP	28.9	28.9	33.3	38.2
Effective ownership through TC PipeLines, LP:				
GTN/Bison	20.2	7.2	8.3	-
Great Lakes	13.4	13.4	15.5	17.7

5

Represents our 61.7 per cent ownership interest.

6

Included as of June 2011.

7

Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

Canadian Pipelines

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Net income			
Canadian Mainline net income	**361**	187	246
Canadian Mainline comparable earnings	**277**	187	246
NGTL System	**243**	208	200
Average investment base			
Canadian Mainline	**5,841**	5,737	6,179
NGTL System	**5,938**	5,501	5,074

Comparable EBITDA and net income for our rate-regulated Canadian Pipelines are primarily affected by our approved ROE, our investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and taxes also impact comparable EBITDA but do not have a significant impact on net income as they are almost entirely recovered in revenue on a flow-through basis.

Canadian Mainline's comparable earnings this year increased by $90 million compared to 2012 because of the impact of the NEB decision. Among other items, the NEB decision approved an ROE of 11.50 per cent on 40 per cent deemed common equity for the years 2012 through 2017 compared to the last approved ROE of 8.08 per cent on 40 per cent deemed common equity that was used to record earnings in 2012. The NEB decision also approved an incentive mechanism based on total net revenues. The 2013 increase in comparable EBITDA is mainly due to the higher ROE plus incentive earnings. Net income of $361 million recorded in 2013 included $84 million related to the 2012 impact of the NEB decision, which was excluded from comparable earnings. Net income in 2012 was $59 million lower than 2011 because there were no incentive earnings and the average investment base was lower as annual depreciation outpaced our capital investment.

Net income in 2013 for the NGTL System was $35 million higher than 2012 because of a higher average investment base associated with 2012 and 2013 capital expenditures and the impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013. The settlement included an ROE of 10.10 per cent on 40 per cent deemed common equity, compared to an ROE of 9.70 per cent on 40 per cent deemed equity in 2012, and included annual fixed amounts for certain OM&A costs. Net income in 2012 was $8 million higher than 2011, mainly due to a growing investment base, partially offset by lower incentive earnings.

Comparable EBITDA and EBIT for the Canadian pipelines reflect the variances discussed above as well as variances in depreciation, financial charges and income tax which are substantially recovered in revenue on a flow-through basis and, therefore, do not have a significant impact on net income.

U.S. and International Pipelines

EBITDA for our U.S. operations is affected by contracted volume levels, actual volumes delivered and the rates charged, as well as by the cost of providing services, including OM&A and other costs, and property taxes.

ANR is also affected by the level of contracting and the determination of rates driven by the market value of its storage capacity, storage related transportation services, and incidental commodity sales. ANR's pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of its business.

Comparable EBITDA for the U.S. and International Pipelines was US$119 million lower in 2013 than 2012. This was due to the net effect of:

- lower transportation and storage revenues at ANR offset by higher incidental commodity sales
- higher OM&A and other costs relating to services provided by other pipelines to ANR
- lower revenue at Great Lakes because of uncontracted capacity
- lower contributions from GTN and Bison due to the reduction of our effective ownership in each pipeline from 83 per cent in 2012 to 50 per cent, effective July 1, 2013
- higher contributions from Portland due to higher short term revenues.

Comparable EBITDA for the U.S. and International Pipelines was US$97 million lower in 2012 than 2011. This was due to the net effect of:

- lower revenue at Great Lakes because of lower rates and uncontracted capacity
- lower transportation and storage revenues at ANR, along with lower incidental commodity sales
- higher OM&A and costs at ANR
- incremental earnings from the Guadalajara pipeline which started operations in June 2011.

Comparable depreciation and amortization

Comparable depreciation and amortization was $80 million higher in 2013 than in 2012 mainly because of a higher NGTL System investment base and higher composite depreciation rate in the 2013-2014 Settlement, as well as the impact of the NEB decision. Depreciation and amortization was $10 million higher in 2012 than in 2011 mainly because Bison began operations in January 2011 and Guadalajara began operations in June 2011.

Business development

In 2013, business development expenses were $6 million higher than last year and $23 million lower in 2012 compared to 2011. Both variances are mainly due to a change in scope on the Alaska pipeline project. See page 32 for further discussion on Alaska.

OUTLOOK

Canadian Pipelines

Earnings

Earnings for Canadian Pipelines are affected most significantly by changes in investment base, ROE and capital structure, and also by the terms of toll settlements or other toll proposals approved by the NEB.

For 2014, we expect the Canadian Mainline will continue to operate under the direction of the NEB decision which included an ROE of 11.50 per cent. We expect 2014 earnings to be in line with 2013.

We expect the NGTL System investment base to continue to grow as we connect new natural gas supply in northeastern B.C. and western Alberta and respond to growing demand in the oil sands market in northeast Alberta. We expect the growing investment base to have a positive impact on earnings in 2014.

We also anticipate a modest level of investment in our other Canadian rate-regulated natural gas pipelines, but expect the average investment bases of these pipelines to continue to decline as annual depreciation outpaces capital investment, reducing their year-over-year earnings.

Under the current regulatory model, earnings from Canadian rate-regulated natural gas pipelines are not materially affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contracted capacity levels.

U.S. Pipelines

Earnings

U.S. Pipeline earnings are affected by the level of contracted capacity and the rates charged to customers. Our ability to recontract or sell capacity at favourable rates is influenced by prevailing market conditions and competitive factors, including alternatives available to end use customers in the form of competing natural gas pipelines and supply sources, in addition to broader macroeconomic conditions that might impact demand from certain customers or market segments. Earnings are also affected by the level of OM&A and other costs, which includes the impact of safety, environmental and other regulator's decisions.

Many of our U.S. natural gas pipelines are backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance. ANR and Great Lakes have had more commercial exposure from transportation and storage contract renewals which resulted in reduced earnings in 2012 and 2013 as transportation and storage values were depressed to historically low levels.

ANR and Great Lakes are examining commercial, regulatory and operational changes to optimize their position from positive developments in supply fundamentals, particularly in the Utica/Marcellus shale plays, combined with continued growth in end use markets for natural gas. In addition, significant efforts to reduce costs for our U.S. pipelines operations are underway and are expected to help with the near term revenue challenges. Overall in 2014, we expect earnings from our U.S. Pipelines to be consistent with 2013.

Mexican Pipelines

Overall earnings from our Mexican pipelines in 2014 are expected to be higher than 2013 due to the Tamazunchale Pipeline Extension which is expected to be placed in service in second quarter 2014. The 2014 earnings for our current operating assets are expected to be consistent with 2013 due to the nature of the long-term contracts applicable to our Mexican pipeline systems.

Capital expenditures

We spent a total of $1.8 billion in 2013 for our natural gas pipelines in Canada, the U.S. and Mexico, and expect to spend $2 billion in 2014 primarily on the NGTL System expansion projects, the Topolobampo and Mazatlan pipelines in Mexico, and the Prince Rupert and Coastal GasLink LNG pipelines. See page 82 for further discussion on liquidity risk.

UNDERSTANDING THE NATURAL GAS PIPELINES BUSINESS

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs.

Our natural gas pipeline business builds, owns and operates a network of natural gas pipelines in North America that connects locations where gas is produced or interconnects with other pipelines to end customers such as local distribution companies, power generation facilities, industrial operations and other pipeline interconnects or end-users. The network includes pipelines that are buried underground and transport natural gas under high pressure, compressor stations that act like pumps to move the large volumes of natural gas along the pipeline and meter stations that record the amount of natural gas coming on the network at receipt locations and leaving the delivery locations.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated in Canada by the NEB, in the U.S. by the Federal Energy Regulatory Commission (FERC) and in Mexico by the Comisión Reguladora de Energía (CRE). The regulators approve construction of new pipeline facilities and ongoing operations of the infrastructure.

Regulators in Canada, the U.S. and Mexico allow us to recover costs to operate the network by collecting tolls, or payments, for services. These costs include OM&A costs, income and property taxes, interest on debt, depreciation expense to recover invested capital, and a return on the capital invested. The regulator reviews our costs to ensure they are prudent, and approves tolls that provide us a reasonable opportunity to recover them.

Within their respective jurisdictions, the FERC and CRE approve maximum transportation rates. These rates are cost based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for investors. The pipeline operator may negotiate lower rates with shippers.

Sometimes we enter into agreements or settlements with our shippers for tolls and cost recovery, which may include mutually beneficial performance incentives. The regulator must approve a settlement for it to be put into effect.

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. Due to the NEB decision, the Canadian Mainline was required to fix its contracted tolls for five years (2013-2017) and defer certain costs to the end of the five-year period. The Mainline was also given flexibility to price its discretionary or uncontracted services in order to maximize its revenue.

The FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they allow for the collection of the variance between actual and expected revenue and costs into future years. This difference in U.S. regulation puts our U.S. pipelines at risk for the difference in expected and actual costs and revenues between rate cases. If revenues no longer provide a reasonable opportunity to recover costs, we can file with the FERC for a new determination of rates, subject to any moratorium in effect. Similarly, the FERC may institute proceedings to lower tolls if they consider returns to be too high.

Our Mexican pipelines are also regulated and have approved tariffs, services and related rates. However, the contracts underpinning the construction and operation of the facilities in Mexico 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.

Business environment and strategic priorities

The North American natural gas pipeline network has developed to connect supply to market. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supplies as well as changing demand.

We have a significant pipeline footprint in the WCSB and transport approximately 75 per cent of total WCSB production to markets within and outside of the basin. Our pipelines also source natural gas, to a lesser degree, from the other major basins including the Appalachian (Utica and Marcellus), Rockies, Williston, Haynesville, Fayetteville and Anadarko as well as the Gulf of Mexico.

Increasing supply

The WCSB spans almost all of Alberta and extends into B.C., Saskatchewan, Yukon and Northwest Territories and is Canada's primary source of natural gas. The WCSB is currently estimated to have 150 trillion cubic feet of remaining conventional resources and a technically accessible unconventional resource base of almost 780 trillion cubic feet. The total WCSB resource base has recently more than quadrupled with the advent of technology that can economically access unconventional gas areas in the basin. We expect production from the WCSB to increase slightly in 2014 after decreasing every year since 2006. WCSB production is expected to continue to increase over the next several years. The Montney and Horn River shale play formations in northeastern B.C. are also part of the WCSB and have recently become a significant source of natural gas. We expect production from these sources, currently 2 Bcf/d, to grow to approximately 6 Bcf/d by 2020, depending on natural gas prices and the economics of exploration and production.

The primary sources of natural gas in the U.S. are the U.S. shale areas, Gulf of Mexico and the Rockies. The U.S. shales are the biggest area of growth which we estimate will meet almost 50 per cent of the overall North American gas demand by 2020. Of the shale areas in the U.S, the Utica, Marcellus, Haynesville, Barnett, Eagle Ford and Fayetteville are the major supply sources.

The supply of natural gas in North America is forecast to increase significantly over the next decade (by approximately 20 Bcf/d or 22 per cent by 2020), and is expected to continue to increase over the long term for several reasons:

- new technology, such as horizontal drilling in combination with multi-stage hydraulic fracturing or fracking, is allowing companies to access unconventional resources economically. This is increasing the technically accessible resource base of existing basins and opening up new producing regions, such as the Marcellus and Utica in the U.S. northeast, and the Montney and Horn River areas in northeastern B.C.
- these new technologies are also being applied to existing oil fields where further recovery of the resource is now possible. High oil prices, particularly compared to North American natural gas prices, have resulted in an increase in exploration and production of liquid-rich hydrocarbon basins. There is often associated gas in these areas (for example, the Bakken oil fields) which increases the overall gas supply for North America.

The development of shale gas basins that are located close to existing markets, particularly in the northeast U.S., has led to an increase in the number of supply choices and is changing historical gas pipeline flow patterns, generally from long-haul, long-term firm contracted capacity to shorter-distance, shorter-term contracts. While the Canadian Mainline has also seen this shift following the NEB decision, we have seen a considerable volume of long-haul transportation recontracted through 2014.

While the increase in supply, particularly in northeastern B.C., has created opportunities for us to build and plan new large pipeline infrastructure on the NGTL System to move the natural gas to markets, including proposed LNG exports, the majority of existing Canadian and U.S. pipelines, including ours, have focused on smaller debottlenecking or short pipe connections as part of any new infrastructure development.

Changing demand

The growing supply of natural gas has resulted in relatively low natural gas prices in North America, which have supported increased demand for natural gas particularly in the following areas:

- natural gas-fired power generation
- petrochemical and industrial facilities
- the production of Alberta oil sands
- exports to Mexico to fuel new power generation facilities.

Natural gas producers are also assessing opportunities to sell natural gas to global markets, which would involve connecting natural gas supplies to new LNG export terminals proposed primarily along the west coast of B.C., and on the U.S. Gulf of Mexico. Assuming the receipt of all necessary regulatory and other approvals, these facilities are expected to become operational later in this decade. The addition of these new markets creates opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

More competition

Changes in supply and demand levels and locations have resulted in increased competition for transportation services throughout North America. Development technology for shale gas supply basins that are closer to markets historically served has resulted in changes to flow patterns of existing natural gas pipeline infrastructure from long haul to shorter haul distances particularly with the large development of U.S. northeast supply. Along with other pipelines, we are restructuring our tolls and service offerings to capture this growing northeast supply and North American demand.

Strategic priorities

We are focused on capturing opportunities resulting from growing natural gas supply, and connecting new markets, while satisfying increasing demand for natural gas within existing markets.

We are also focused on adapting our existing assets to the changing gas flow dynamics.

The Canadian Mainline continued to be a focal point in 2013 following the receipt and implementation of the NEB decision. Following the NEB decision, we reached an LDC Settlement that addresses issues associated

with the NEB decision. The LDC Settlement reflects our focus on developing a framework that balances the needs of our shippers while at the same time ensuring a reasonable opportunity to recover the capital from our existing facilities and any new facilities required to serve existing and new markets.

The NGTL System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in Western Canada to domestic and export markets. It faces competition for connection to supply, particularly in northeastern B.C., where the largest new source of natural gas has access to two existing competing pipelines. Connections to new supply and new or growing demand supports new capital expansions of the NGTL System. We expect supply in the WCSB to grow from its current level of approximately 14 Bcf/d to approximately 17 Bcf/d by 2020. The NGTL System is well positioned to connect WCSB supply to meet expected demand for LNG exports on the B.C. coastline. Obtaining the necessary regulatory approvals to extend and expand the NGTL System into northeast B.C. to connect the Montney shale area will be a key focus in 2014.

Our U.S. pipeline assets are positioned well for anticipated connections to growth in supply and markets for the following reasons:

- expected continued growth in gas-fired generation and therefore load on our pipes, including the new proposed Carty lateral on the GTN system to deliver natural gas to a new power plant in Oregon
- growth in industrial load in response to robust levels of natural gas supply, including connections to the ANR System to serve a new nitrogen fertilizer plant in Iowa
- Utica/Marcellus supply growth and Gulf Coast LNG export development supporting ANR utilization, including the Lebannon Lateral project attracting Utica supply to the ANR system with additional phases of further expansion expected.

Management expects to divest our remaining U.S. natural gas pipeline assets into TC PipeLines, LP over time as a means of funding a portion of our capital growth program.

Our focus in Mexico in 2014 is to complete the Tamazunchale Pipeline Extension project and to advance the construction phase for the Mazatlan and Topolobampo pipelines. We continue to be very interested in the further development of natural gas infrastructure in Mexico and will work to advance future projects that align with the investment profile of our current set of assets.

We continue to assess repurposing opportunities for our existing natural gas pipelines assets, including the possibility of converting existing infrastructure from natural gas to crude oil service. In 2007, we received NEB approval to convert one of our Canadian Mainline gas pipelines to crude oil service for the original Keystone project. Another project, the Energy East Pipeline is planning, subject to regulatory approval, to utilize approximately 3,000 km (1,864 miles) of the Canadian Mainline from the Alberta border to a point in eastern Ontario, southeast of Ottawa. As a result, we are working closely with our shipper community to ensure their firm service needs will continue to be met following the planned conversion.

SIGNIFICANT EVENTS

Canadian Pipelines

In 2013, we completed and placed in service approximately $730 million of pipeline projects to expand and extend the NGTL System and $160 million to expand the Canadian Mainline.

NGTL System

In addition to completing and placing in service new pipeline projects to expand the NGTL System, in 2013 the NEB approved approximately $290 million in additional expansions that are currently in various stages of development or construction but were not in service at the end of 2013.

On November 8, 2013, we filed an application with the NEB to construct and operate the North Montney Project, which is an extension and expansion of the NGTL System to receive and transport natural gas from the

North Montney area of B.C. The estimated capital cost of the project is $1.7 billion and it consists of approximately 300 km (186 miles) of pipeline.

The NEB approved the 2013-2014 NGTL Settlement and final 2013 rates, as filed, in November 2013. We expect the final tolls for 2014 for the NGTL System will be determined on the basis of the NGTL settlement process.

Canadian Mainline

In March 2013, we received the NEB decision on our application to change the business structure and the terms and conditions of service for the Canadian Mainline and implemented the decision on July 1, 2013. 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.

The NEB decision established a Tolls 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.

The Mainline and the three largest Canadian local distribution companies entered into a settlement (LDC Settlement) which was filed with the NEB for approval in December 2013. The LDC Settlement, if approved, will establish new fixed tolls for 2015 to 2020 and maintain tolls for 2014 at the current rates. The LDC Settlement calculates tolls for 2015 on a base ROE of 10.10 per cent on 40 per cent deemed common equity. It also includes an incentive mechanism that requires a $20 million (after tax) annual contribution by us from 2015 to 2020, which could result in a range of ROE outcomes from 8.70 per cent to 11.50 per cent.

The LDC Settlement will enable the addition of facilities in the Eastern Triangle to serve immediate market demand for supply diversity and market access. The LDC Settlement is intended to provide a market-driven, stable, long-term accommodation of future demand in this region in combination with the anticipated lower demand for transportation on the Prairies Line and the Northern Ontario Line while providing a reasonable opportunity to recover our costs. The LDC Settlement also retains pricing flexibility for discretionary services and implements certain tariff changes and new services as required by the term of the settlement.

The NEB decision remains in effect pending the outcome of the LDC Settlement application.

On January 31, 2014, shippers on the Canadian Mainline elected to renew approximately 2.5 Bcf/d of their contracts through November 2016. This represents a significant amount of volume renewal, especially by Canadian shippers.

U.S. Pipelines

Bison and GTN

In July 2013, we sold an additional 45 per cent interest in each of GTN and Bison to TC PipeLines, LP. for an aggregate purchase price of US$1.05 billion. We continue to hold a 30 per cent direct ownership interest in both pipelines. We also hold 28.9 per cent interest in, and are the General Partner of, TC PipeLines, LP.

ANR Lebanon Lateral Reversal Project

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

Great Lakes

In November 2013, we received FERC approval for a rate settlement with our shippers resulting in maximum recourse rates increasing by approximately 21 per cent resulting in a modest increase in revenues derived from our recourse rate contracts. The settlement includes a 17 month moratorium through March 2015 and requires us to have new rates in effect by January 1, 2018.

Mexican Pipelines

Topolobampo and Mazatlan Pipeline Projects.

Permitting and engineering 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 from El Encino, Chihuahua and interconnects with third party pipelines in El Oro, Sinaloa to Topolobampo, Sinaloa. 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 Comisión Federal de Electricidad (CFE) and are expected to be in service mid to late 2016.

Tamazunchale Pipeline Extension Project

The construction of the US$500 million Tamazunchale Pipeline Extension project is proceeding although delays have occurred due to a significant number of archeological finds within the pipeline route. It is expected these findings and related alternative construction will move the project scheduled in-service date to second quarter 2014. As these types of findings are not uncommon in significant infrastructure projects in Mexico, contractual relief for such delays is provided. We continue to work with local, state and federal authorities to minimize and mitigate ground disturbance at the specific sites as well as to minimize impact to the scheduled in-service date.

LNG Pipeline Projects

Coastal GasLink

In June 2012, we were selected to design, build, own and operate the proposed Coastal GasLink project. The estimated $4 billion, 650 km (404 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.

We are currently focused on community, landowner, government and First Nations engagement as the project advances through the regulatory process. We filed the Application for an Environmental Assessment Certificate with the B.C. Environmental Assessment Office (BCEAO) in January 2014.

The pipeline would be placed in service near the end of the decade, subject to a final investment decision to be made by LNG Canada after obtaining final regulatory approvals. We continue to advance this project and all costs would be recoverable should the project not proceed.

Prince Rupert Gas Transmission Project

We have been selected to design, build, own and operate the proposed $5 billion, 750 km (466 miles) Prince Rupert Gas Transmission Project. The proposed pipeline will transport natural gas primarily from the North Montney gas-producing region near Fort St John, B.C. to the proposed Pacific Northwest LNG export facility near Prince Rupert, B.C.

We are currently focused on First Nations, community, landowner and government engagement as the Prince Rupert pipeline project advances through the regulatory process with the BCEAO. We continue to refine our study corridor based on consultation and detailed studies to date. A final investment decision to construct the project, for a planned in-service date of late 2018, is expected to be made following final regulatory approvals.

We continue to advance this project and all costs would be fully recoverable should the project not proceed.

Alaska LNG Project

The State of Alaska is proposing new legislation that would transition from the *Alaska Gasline Inducement Act* and enable a new commercial arrangement to be established with us, the three major producers, and the Alaska Gasline Development Corp. It has also been agreed that an LNG export project, rather than a pipeline to Alberta, is currently the best opportunity to commercialize Alaska North Slope gas resources in current market conditions. It is anticipated that two years of front end engineering will be completed before further commitments to commercialize the project will be made.

BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 76 for information about general risks that affect the company as a whole.

WCSB supply for downstream connecting pipelines

Although we have diversified our sources of natural gas supply, many of our North American natural gas pipelines and transmission infrastructure assets depend largely on supply from the WCSB. There is competition for this supply from several pipelines, demand within the basin, and in the future, demand for pipelines proposed for LNG exports from the west coast of B.C. An overall decrease in production and/or competing demand for supply, could impact throughput on WCSB connected pipelines that in turn could impact overall revenues generated. The WCSB has considerable reserves, but how much of it is actually produced will depend on many variables, including the price of natural gas, basin-on-basin competition, downstream pipeline tolls, demand within the basin and the overall value of the reserves, including liquids content.

Market access to other supply

We compete for market share with other natural gas pipelines. New supply basins being developed closer to markets we have historically served may reduce the throughput and/or distance of haul on our existing pipelines that may impact revenue. The long-term competitiveness of our pipeline systems will depend on our ability to adapt to changing flow patterns by offering alternative transportation services at prices that are acceptable to the market.

Competition for greenfield expansion

We face competition from other pipeline companies seeking opportunities to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our investment hurdles or projects that proceed with lower overall financial returns.

Demand for pipeline capacity

Demand for pipeline capacity is ultimately the key driver that enables pipeline transportation services to be sold. Demand for pipeline capacity is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition and pricing of alternative fuels. Renewal of expiring contracts, and the opportunity to charge and collect a toll the market requires depends on the overall demand for transportation service. A change in the level of demand for our pipeline transportation services could impact revenues.

Regulatory risk

Decisions by regulators can have an impact on the approval, timing, construction, operation and financial performance of our natural gas pipelines. There is a risk that decisions are delayed or are not favourable that could impact revenues and the opportunity to further invest capital in our systems. There is also risk of a regulator disallowing a portion or all prudently incurred costs, now or at some point in the future.

The regulatory approval process for larger infrastructure projects including the time it takes to receive a decision could be slowed or unfavorable due to the influence from the evolving role of activists and their impact on public opinion and government policy related to natural gas pipeline infrastructure development.

Increased scrutiny of operating processes by the regulator or other enforcing agencies, has the potential to increase operating costs. There is a risk of an impact to revenues if these costs are not fully recoverable.

We continuously monitor regulatory developments and decisions to determine the possible impact on our gas pipelines business. We also work closely with our stakeholders in the development of rate, facility and tariff applications and negotiated settlements, where possible.

Operational

Keeping our pipelines operating safely and reliably is essential to the success of our business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced revenue and can affect corporate reputation as well as customer and public confidence in our operations. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly, and repair or replace them whenever necessary. We also calibrate the meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

Oil Pipelines

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

Strategy at a glance

With the increasing production of crude oil in Alberta and the U.S. and the growing demand for secure, reliable sources of energy, developing new liquids pipeline capacity and related infrastructure is essential.

We continue to focus on accessing and delivering growing North American crude oil supply to key markets, and are planning to expand our crude oil transportation infrastructure to deliver supply directly from the production site seamlessly along a contiguous path to the market.

Construction of these infrastructure projects will provide North America with a key crude oil transportation network to transport growing crude oil supply directly to key markets and provide opportunities for us to further expand our liquids pipelines business.

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

		length	description	ownership
	Oil pipelines			
23	Keystone Pipeline System (includes Gulf Coast Project)	4,247 km (2,639 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, Cushing, Oklahoma, and to the U.S. Gulf Coast refining market	100%
	Under construction			
24	Cushing Marketlink Receipt Facility	Crude oil receipt facilities	To facilitate the transportation of crude oil from the market hub at Cushing, Oklahoma to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System	100%
25	Houston Lateral and Terminal	77 km (48 miles)	To transport crude oil from the Keystone Pipeline System to Houston, Texas	100%
26	Keystone Hardisty Terminal	Crude oil terminal	Crude oil terminal to be located at Hardisty, Alberta, providing western Canadian producers with new crude oil batch accumulation tankage and access to the Keystone Pipeline System	100%
	In development			
27	Bakken Marketlink Receipt Facility	Crude oil receipt facilities	To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL	100%
28	Grand Rapids Pipeline	500 km (300 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland market region	50%
29	Keystone XL	1,897 km (1,179 miles)	Crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
30	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%
31 32	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%
33	Energy East Pipeline	4,500 km (2,700 miles)	To transport crude oil from western Canada to eastern refineries and export markets	100%

RESULTS

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**[1]
Keystone Pipeline System	**766**	712	589
Oil Pipelines Business Development	**(14)**	(14)	(2)
Oil Pipelines comparable EBITDA	**752**	698	587
Comparable depreciation and amortization	**(149)**	(145)	(130)
Oil Pipelines comparable EBIT	**603**	553	457
Comparable EBIT denominated as follows			
Canadian dollars	**201**	191	159
U.S. dollars	**389**	363	301
Foreign exchange impact	**13**	(1)	(3)
Oil Pipelines comparable EBIT	**603**	553	457

1 Results in 2011 are for 11 months.

Comparable EBITDA

Comparable EBITDA for the Keystone Pipeline System was $54 million higher this year than in 2012. This increase reflected higher revenues primarily resulting from:

- higher volumes
- the impact of higher final fixed tolls on committed pipeline capacity to Cushing, Oklahoma, which came into effect in July 2012.

Results in 2013 were positively impacted by the stronger U.S. dollar compared to 2012.

Comparable EBITDA for the Keystone Pipeline System was $123 million higher in 2012 than in 2011. This increase reflected higher revenues primarily resulting from:

- higher contracted volumes
- the impact of higher final fixed tolls on committed pipeline capacity to Wood River and Patoka, in Illinois, which came into effect in May 2011
- the impact of higher final fixed tolls on committed pipeline capacity to Cushing, Oklahoma, which came into effect in July 2012
- twelve months of earnings recorded in 2012 compared to eleven months in 2011.

We began recording EBITDA for the Keystone Pipeline System in February 2011, when we began delivering crude oil to Cushing, Oklahoma.

Business development

Business development expenses in 2012 were $12 million higher than 2011 mainly because of increased business development activity on various oil pipeline development projects.

Comparable depreciation and amortization

Comparable depreciation and amortization was $15 million higher in 2012 than in 2011 because 12 months of depreciation was recorded in 2012 compared to 11 months in 2011.

OUTLOOK

Earnings

We expect earnings to increase in 2014 compared to 2013, due to the completion of the Gulf Coast segment of the Keystone Pipeline System allowing commencement of crude oil transportation services to the U.S. Gulf Coast. Earnings are expected to increase over time as projects currently in development are placed in service.

Capital expenditures

We spent a total of $2.5 billion in 2013, and expect to spend approximately $2.3 billion in 2014, mainly related to Heartland Pipeline, Northern Courier Pipeline and Grand Rapids Pipeline. This amount excludes Keystone XL. The amount and timing of capital spending on Keystone XL will be dependent on the decision by the DOS to issue a Presidential Permit. See page 82 for further discussion on liquidity risk.

UNDERSTANDING THE OIL PIPELINES BUSINESS

Oil pipelines move crude oil from major supply sources to refinery markets so the crude oil can be refined into various petroleum products.

We generate earnings from our oil pipelines mainly by providing pipeline capacity to shippers in exchange for fixed monthly payments that are not linked to actual throughput volumes. Uncontracted capacity is offered to the market on a spot basis which provides opportunities to generate incremental earnings.

The terms of service and fixed monthly payments are determined by transportation service arrangements negotiated with shippers. These arrangements are typically long term, and provide for the recovery of costs we incur to construct and operate the system.

Business environment

Increasing crude oil supply production in Canada and the U.S. has increased the demand for new crude oil pipeline infrastructure and, as a result, we are pursuing opportunities to connect growing North American crude oil supplies to key markets.

Alberta produces the majority of the crude oil in the WCSB which is the primary source of crude oil supply for the Keystone Pipeline System. In a 2013 Canadian Association of Petroleum Producers (CAPP) report, the WCSB produced an estimated 1.2 million Bbl/d of conventional crude oil and condensate, and 1.8 million Bbl/d of Alberta oil sands crude oil a total of approximately 3.0 million Bbl/d. The production of conventional crude oil in western Canada continues to grow with 2012 to 2013 growth representing the largest year over year change to the previous forecast.

In its 2013 report, the Alberta Energy Regulator (AER) estimated there are approximately 170 billion barrels of remaining established conventional and oil sands reserves in Alberta. In June 2013, CAPP forecasted WCSB crude oil supply would increase to 3.9 million Bbl/d by 2015 and to 4.9 million Bbl/d by 2020. Its 2013 forecast for western Canadian production of conventional and unconventional crude oil in 2025 is 300,000 Bbl/d higher than its forecast in 2012.

Oil sands production

Despite increases in production from conventional sources and new shale oil production (including the Canadian Bakken and Cardium formations), the oil sands will continue to make up most of the crude oil production from the WCSB. CAPP estimated that industry capital spending on oil sands development held steady at $23 billion for 2013.

Oil sands projects have a long reserve life. According to the Responsible Canadian Energy Report issued by CAPP, it is estimated that a typical oil sands mine has a 25 to 50 year lifespan and an in-situ operation will run

10 to 15 years on average. That aligns with producers' desire to secure long-term connectivity of their reserves to market. The Keystone Pipeline System and the proposed Energy East Pipeline will provide producers with needed pipeline capacity and are underpinned by long term commercial contracts.

Demand for infrastructure within Alberta

Growth in oil sands production is also driving the need for new intra-Alberta pipelines, like our Grand Rapids Pipeline, that can move crude oil production from the source to market hubs at Edmonton/Heartland and Hardisty, Alberta and which can also move diluent from Edmonton/Heartland region to the production area in Northern Alberta. We are constructing the Heartland Pipeline and TC Terminals projects to support these market hubs which allow shippers the ability to connect with the Keystone Pipeline System, Energy East Pipeline and other pipelines that transport crude oil outside of Alberta.

Growth in U.S. production

According to the International Energy Agency World Energy Outlook 2013 report, by 2015, the U.S. is set to surpass Saudi Arabia as the world's largest oil producer. The U.S. Energy Information Administration (EIA) projects nearly 2.0 million Bbl/d of U.S. production growth, peaking at 9.6 million Bbl/d by 2019. Higher production volumes result mainly from shale oil production. EIA forecasts approximately 4.8 million Bbl/d of shale oil production by 2020 and declining by 2022.

Shale oil supply growth is mainly from the Bakken formation of the Williston basin in North Dakota and Montana, the Permian basin in south Texas and Woodford shale area of the Arkoma basin in Oklahoma. These shale production areas represent some of the sources of crude oil supply for our Bakken and Cushing Marketlink projects.

Growing U.S. production has contributed to increased crude oil supply at the Cushing, Oklahoma market hub and resulted in increased demand for additional pipeline capacity between Cushing, Oklahoma and the U.S. Gulf Coast refining market. Our Gulf Coast segment of the Keystone Pipeline System and Cushing Marketlink project provide needed pipeline capacity to transport growing crude oil supply at Cushing, Oklahoma to the U.S. Gulf Coast.

Even with growth in U.S. crude oil production, the EIA report predicts the U.S. will remain a net importer of crude oil, importing 7.7 million Bbl/d into 2040. Growing production in the west Texas Permian, south Texas Eagle Ford and Williston basins, is primarily light crude oil, and is expected to compete with light imports from countries such as Nigeria and Saudi Arabia. Gulf Coast refiners are expected to continue to prefer Canadian heavy crude oil because their refineries are mainly configured to process heavy crude oil and cannot easily switch to processing the new light shale oil in large quantities without significant capital investments. Gulf Coast refineries currently require approximately 3.5 million Bbl/d of heavy and medium crude oil, and the level of demand is not expected to change significantly in the future. The Keystone Pipeline System is well positioned to deliver Canadian crude oil to this significant market.

Refineries in eastern Canada currently process primarily light crude oil from west Africa and the Middle East, so are better able to handle light shale oil. Many of these refineries have recently begun transporting domestic light crude oil in small quantities by rail at a cost significantly higher than the cost to ship by pipeline. This has created a significant demand for pipelines to connect eastern Canada with growing Bakken and WCSB light crude oil production. We anticipate that our Energy East Pipeline project, once approved and constructed, will meet this demand.

SIGNIFICANT EVENTS

Keystone Pipeline System

We finished constructing the 780 km (485 miles) 36-inch pipeline of the Gulf Coast project, an extension of the Keystone Pipeline System, from Cushing, Oklahoma to the U.S. Gulf Coast. Crude oil transportation service on the project began January 22, 2014. We are projecting an average pipeline capacity of 520,000 Bbl/d for the first year of operation.

Houston Lateral and Terminal

Construction continues on the US$400 million, 77 km (48 miles) Houston Lateral pipeline and tank terminal to transport crude oil to Houston, Texas refineries. We anticipate the capacity of the lateral will be similar to that of the Gulf Coast project and the terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in mid-2015.

Cushing Marketlink

Construction continues on the Cushing Marketlink receipt facilities at Cushing, Oklahoma. Cushing Marketlink will facilitate the transportation of crude oil from the market hub at Cushing to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System. Construction is expected to be completed in the first half of 2014.

Keystone XL

In March 2013, the DOS released its Draft Supplemental Environmental Impact Statement for the Keystone XL project. The impact statement reaffirmed construction of the 830,000 Bbl/d Keystone XL project would not result in any significant impact to the environment.

On January 31, 2014, the DOS released its Final Supplemental Environmental Impact Statement (FSEIS) for the Keystone XL project. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is "unlikely to significantly impact the rate of extraction in the oil sands" and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more greenhouse gas 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.

On February 19, 2014, a Nebraska district court ruled that the state Public Service Commission, rather than Governor Dave Heineman, has the authority to approve an alternative route through Nebraska for the Keystone XL project. We disagree with the decision of the Nebraska district court and will now analyze the judgment and decide what next steps may be taken. Nebraska's Attorney General has filed an appeal.

We anticipate the pipeline, which will extend from Hardisty, Alberta to Steele City, Nebraska, to be in service approximately two years following the receipt of the Presidential Permit. The US$5.4 billion cost estimate will increase depending on the timing and conditions of the permit. Any capital cost increase above the initial estimated capital cost, up to a specified amount, is shared between us and the shippers such that 75 per cent of the change in capital cost is reflected in the fixed payment received by us. Any capital cost increase above the specified amount is shared equally between us and the shippers. As of December 31, 2013, we have invested US$2.2 billion in the project.

Energy East Pipeline

In August 2013, we announced we are moving forward with the 1.1 million Bbl/d Energy East Pipeline as it received approximately 900,000 Bbl/d of firm, long-term contracts in its open season to transport crude oil from western Canada to eastern refineries and export terminals. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets.

Subject to regulatory approvals, the pipeline is anticipated to commence deliveries to Québec in 2018, with service to New Brunswick expected to follow in late 2018. We have begun Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning. We intend to file the necessary regulatory applications in mid-2014 for approvals to construct and operate the pipeline project and terminal facilities.

Northern Courier Pipeline

In April 2013, we filed a permit application with the AER after completing the required Aboriginal and stakeholder engagement and associated field work.

In October 2013, Suncor Energy announced that the Fort Hills Energy Limited Partnership is proceeding with the Fort Hills oil sands mining project and expects to begin producing crude oil in 2017. Our Northern Courier Pipeline project is expected to cost $800 million and will transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta.

Heartland Pipeline and TC Terminals

In May 2013, we announced we had reached binding long-term shipping agreements to build, own and operate the Heartland Pipeline and TC Terminals projects.

The projects will include a 200 km (125 miles) crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton, Alberta. We anticipate the pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined cost estimated at $900 million and are expected to be placed in service in 2016.

We filed a permit application for the terminal facility in May 2013 and for the pipeline in October 2013 with the AER, after completing the required Aboriginal and stakeholder engagement and associated field work. In February 2014, the application for the terminal facility was approved.

Keystone Hardisty Terminal

In May 2013, we started construction on the Keystone Hardisty Terminal which we anticipate will have a storage capacity of up to 2.6 million barrels of crude oil. The $300 million crude oil terminal at Hardisty, Alberta is expected to be in service in 2016.

Grand Rapids Pipeline

In May 2013, we filed a permit application for the Grand Rapids Pipeline with the AER after completing the required Aboriginal and stakeholder engagement and associated field work. The dual pipeline system could transport up to 900,000 Bbl/d of crude oil and 330,000 Bbl/d of diluent.

Along with a partner, we will each own 50 per cent of the project and we will operate the system, which is expected to cost $3 billion. Our partner has entered into a long-term commitment to ship crude oil and diluent on this pipeline system.

Subject to regulatory approvals, the system is expected to be placed in service in multiple stages, with initial crude oil service by mid-2015 and the complete system in service in the second half of 2017.

BUSINESS RISKS

The following are risks specific to our oil pipelines business. See page 76 for information about general risks that affect the company as a whole, including other operational risks, health, safety and environment (HSE) risks, and financial risks.

Operational

Optimizing and maintaining availability of our oil pipelines is essential to the success of our oil pipelines business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced fixed payment revenues and spot volume opportunities. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly and repair them whenever necessary.

Regulatory

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation and financial performance of our oil pipelines. Public opinion about crude oil development and production may also have an adverse impact on the regulatory process. There are some individuals and interest groups that are expressing their opposition to crude oil production by opposing the construction of oil pipelines. We manage this risk by continuously monitoring regulatory developments and decisions to determine their possible impact on our oil pipelines business and by working closely with our stakeholders in the development and operation of the assets.

Execution, capital costs and permitting

We make substantial capital commitments in large infrastructure projects based on the assumption that the new assets will offer an attractive return on investment in the future. Under some contracts, we share the cost of these risks with customers. While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost risk which may impact our return on these projects. Our capital projects are also subject to permitting risk which may result in construction delays, increased capital cost and, potentially, reduced investment returns.

Crude oil supply and demand for pipeline capacity

Demand for crude oil pipeline capacity is dependent on the level of crude oil supply and demand for refined crude oil products. New producing technologies such as steam assisted gravity drainage and horizontal drilling in combination with hydraulic fracturing are allowing producers to economically increase development of unconventional resources, such as oil sands and shale oil at current crude oil prices, and have resulted in increased demand for new crude oil pipeline infrastructure. A decrease in demand for refined crude oil products could adversely impact the price that crude oil producers receive for their product. Lower margins for crude oil could mean producers curtail their investment in the development of crude oil supplies. Depending on their severity, these factors would negatively impact the opportunities we have to expand our crude oil pipeline infrastructure and, in the longer term, re-contract with shippers as current agreements expire.

Competition

As we continue to develop a competitive position in the North American crude oil transportation market to transport growing WCSB, Williston, Permian and Arkoma basins crude oil supplies to key North American refining markets and export markets, we face competition from other pipeline companies and to a lesser extent, rail companies which also seek to transport these crude oil supplies to the same markets. Our success is dependent on our ability to offer and contract transportation services on terms that are market competitive.

Energy

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 more than 11,800 MW of generation capacity powered by natural gas, nuclear, coal, hydro, wind and solar assets. Our power business in Canada is mainly located in Alberta, Ontario and Québec. Our U.S. power business is located in New York, New England, and Arizona. The assets are largely supported by long-term contracts and some represent low-cost baseload generation, while others are critically located, essential capacity.

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

We own or control approximately 156 Bcf of unregulated natural gas storage capacity in Alberta, accounting for approximately one-third of all storage capacity in the province. When combined with the regulated natural gas storage in Michigan (part of the Natural Gas Pipelines segment), we provide approximately 407 Bcf of natural gas storage and related services.

Strategy at a glance

We are focusing on low-cost, long-life electrical infrastructure and natural gas storage assets supported by strong market fundamentals and the opportunity for long-term contracts with creditworthy counterparties. Our growing investment in natural gas, nuclear, wind, hydro-power and solar generating facilities demonstrates our commitment to clean, sustainable energy.

The growth in demand for power in North America coupled with an electrical infrastructure base that is aging and a societal preference for lower carbon intense electricity production is expected to provide us with the opportunity to participate in new generation and other power infrastructure projects.

Natural gas storage's role in balancing and providing reliability and flexibility to the natural gas system is expected to grow as the market expands and becomes more dynamic as a result of the electric grid's increased reliance on gas-fired capacity to backup ever increasing renewable power and from the addition of LNG export terminals.

1 Includes facilities in development.

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

		generating capacity (MW)	type of fuel	description	location	ownership
	Canadian Power 8,070 MW of power generation capacity (including facilities in development)					
	Western Power 2,636 MW of power supply in Alberta and the western U.S.					
34	Bear Creek	80	natural gas	Cogeneration plant	Grand Prairie, Alberta	100%
35	Cancarb[1]	27	natural gas, waste heat	Facility fuelled by waste heat from an adjacent TransCanada facility that produces thermal carbon black, a by-product of natural gas	Medicine Hat, Alberta	100%
36	Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
37	Coolidge[2]	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
38	Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
39	Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
40	Sheerness PPA	756	coal	PPA for entire output of facility	Hanna, Alberta	100%
41	Sundance A PPA	560	coal	PPA for entire output of facility	Wabamun, Alberta	100%
41	Sundance B PPA (Owned by ASTC Power Partnership[3])	353[4]	coal	PPA for entire output of facility	Wabamun, Alberta	50%
	Eastern Power 2,950 MW of power generation capacity (including facilities in development)					
42	Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
43	Cartier Wind	366[4]	wind	Five wind power projects	Gaspésie, Québec	62%
44	Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%

45	Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
46	Portlands Energy	275[4]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
47	Ontario Solar	36	solar	Four solar facilities	Southern Ontario	100%

		generating capacity (MW)	type of fuel	description	location	ownership
	Bruce Power 2,484 MW of power generation capacity through eight nuclear power units					
48	Bruce A	1,462[4]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
48	Bruce B	1,022[4]	nuclear	Four operating reactors	Tiverton, Ontario	31.6%
	U.S. Power 3,755 MW of power generation capacity					
49	Kibby Wind	132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
50	Ocean State Power	560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
51	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%
52	TC Hydro	583	hydro	13 hydroelectric facilities, including stations and associated dams and reservoirs	New Hampshire, Vermont and Massachusetts (on the Connecticut and Deerfield rivers)	100%
	Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity					
53	CrossAlta	68 Bcf		Underground facility connected to the NGTL System	Crossfield, Alberta	100%
54	Edson	50 Bcf		Underground facility connected to the NGTL System	Edson, Alberta	100%
	In development					
55	Napanee	900	natural gas	Proposed combined-cycle plant	Greater Napanee, Ontario	100%
56	Ontario Solar	50	solar	Acquisition of five remaining solar facilities from	Southern Ontario and New Liskeard, Ontario	100%

Canadian Solar
Solutions Inc. in 2014

1
As at December 31, 2013, both the Cancarb waste heat and thermal carbon black plant were classified as Assets Held for Sale. See Significant Events for further information

2
Located in Arizona, results reported in Canadian Power Western Power.

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

4
Our share of power generation capacity.

RESULTS

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Canadian Power			
Western Power[1]	**380**	335	483
Eastern Power[2]	**347**	345	297
Bruce Power	**310**	14	110
General, administrative and support costs	**(50)**	(48)	(43)
Canadian Power comparable EBITDA[3]	**987**	646	847
Comparable depreciation and amortization	**(172)**	(152)	(141)
Canadian Power comparable EBIT[3]	**815**	494	706
U.S. Power (US$)			
Northeast Power	**370**	257	314
General, administrative and support costs	**(47)**	(48)	(41)
U.S. Power comparable EBITDA	**323**	209	273
Comparable depreciation and amortization	**(107)**	(121)	(109)
U.S. Power comparable EBIT	**216**	88	164
Foreign exchange impact	**7**	-	(4)
U.S. Power comparable EBIT[3] (Cdn$)	**223**	88	160
Natural Gas Storage and other			
Natural Gas Storage and other	**73**	77	84
General, administrative and support costs	**(10)**	(10)	(6)
Natural Gas Storage and other comparable EBITDA[3]	**63**	67	78
Comparable depreciation and amortization	**(12)**	(10)	(12)
Natural Gas Storage and other comparable EBIT[3]	**51**	57	66
Business development comparable EBITDA and EBIT	**(20)**	(19)	(25)
Energy comparable EBIT[3]	**1,069**	620	907
Summary			
Energy comparable EBITDA[3]	**1,363**	903	1,168
Comparable depreciation and amortization	**(294)**	(283)	(261)
Energy comparable EBIT[3]	**1,069**	620	907

Includes Coolidge starting in May 2011.

2

Includes the acquisition of four Ontario Solar facilities in 2013 and Cartier phase two of Gros-Morne starting in November 2012, phase one of Gros-Morne starting in November 2011 and Montagne-Sèche starting in November 2011.

3

Includes our share of equity income from our equity accounted for investments in ASTC Power Partnership, Portlands Energy, Bruce Power and CrossAlta up to December 2012. In December 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent and commenced consolidating their operations.

Comparable EBITDA for Energy was $460 million higher in 2013 than in 2012. The increase was the effect of:

- higher equity income from Bruce Power due to incremental earnings from Units 1 and 2 and lower planned outage days at Unit 4 and an insurance recovery related to the May 2012 Unit 2 electrical generation failure
- higher earnings from U.S. Power mainly because of higher realized capacity prices in New York and higher realized power prices
- higher earnings from Western Power primarily because of higher purchased volumes under the PPAs.

Comparable EBITDA for Energy was $265 million lower in 2012 compared to 2011. This reflected the net effect of:

- lower earnings from Western Power due to the Sundance A force majeure
- incremental earnings from Cartier Wind in Eastern Power and Coolidge in Western Power
- lower equity income from Bruce Power due to increased planned outage days
- lower earnings from U.S. Power because of lower realized power prices, higher load serving costs and reduced water flows at the TC Hydro facilities.

OUTLOOK

Earnings

We expect 2014 earnings from the Energy segment to be slightly lower than 2013, assuming the net effect of:

- lower power prices and lower seasonal natural gas storage price spreads in Alberta
- lower earnings as a result of the sale of Cancarb
- higher realized capacity prices and commodity prices in New York and New England
- incremental earnings from the solar facilities acquired in 2013, as well as the additional facilities expected to be acquired in 2014, offset by lower contributions from Bécancour.

Bruce Power equity income is expected to be consistent with 2013.

Although a significant portion of Energy's output is sold under long-term contracts, revenue from power that is sold under shorter-term forward arrangements or at spot prices will continue to be impacted by fluctuations in commodity prices and changes in seasonal natural gas storage price spreads will impact Natural Gas Storage earnings.

Weather, unplanned outages and unforeseen regulatory changes can play a role in spot markets.

Western Power

Alberta power market fundamentals are strong and new power capacity and transmission projects are being developed to meet growing demand. In step with economic growth, Alberta power demand in 2013 was 2.5 per cent higher than 2012, an annual rate that has been relatively consistent since 2009. The outlook for forward oil prices supports ongoing investment in the oil sands and the associated development is expected to support continuing economic growth and increased power consumption in the province of Alberta. The Alberta Electric System Operator is forecasting that demand growth will continue to be strong at a three per cent plus annual increase over the next 10 years, and estimates that about 7,000 MW of new generation will be required.

The strong growth will afford us ample opportunity to participate in new generation additions and other power infrastructure projects. Spot market power prices are a function of many factors, including supply and demand conditions and natural gas prices. The supply of power is largely dictated by the performance of the coal fleet and wind availability, while power demand is highly influenced by weather and seasonal factors. Average spot market power prices in Alberta in 2013 ($80/MWh) were higher than 2012 ($64/MWh) partly due to three significant long-term coal unit outages, demand growth and higher natural gas prices. In 2014, modest supply additions combined with fewer long-term coal unit outages are expected to result in lower spot prices that are more in line with long run historical price levels.

Natural Gas Storage

Natural gas spreads are currently in cyclical lows with 2014 forward summer/winter spreads below the average experienced in 2013. The strength of summer prices relative to winter will be heavily influenced by season ending storage inventory levels and increased summer flows out of Alberta.

Eastern Power

All of our existing energy assets in Eastern Power are fully contracted. Our Ontario assets are contracted with the Ontario Power Authority (OPA) and, as a result, we are largely shielded from fluctuations in the spot price

of electricity in Ontario. The Ontario Independent Electricity System Operator forecasts slight growth in the demand for power in 2014 as conservation programs and embedded generation offset consumption gains related to stronger economic growth. At the end of 2013, Ontario had retired the majority of its coal-fired fleet.

Bruce Power

In late 2013, the Ontario government released an updated Long-term Energy Plan that introduced a nuclear refurbishment policy framework for select nuclear units, including the Bruce Power facilities that we partially own. Bruce Power is considering the implications of the updated Long-term Energy Plan and the site's refurbishment options.

U.S. Power

U.S. northeast power market areas are expected to have minor growth in load demand in 2014. A larger source of potential growth for power prices will be the expected higher natural gas prices due to the limited import capability into the U.S. northeast markets and better fundamental support with larger 2013/2014 winter season withdrawals from storage.

Average New England ISO power prices increased to US$56/MWh in 2013 from US$36/MWh in 2012, primarily driven by higher gas prices. New England power demand increased by approximately one and a half per cent in 2013 compared to 2012, partly due to cold winter weather and modest gains in the economy. The New England ISO forecasts growth in the demand for power of about one and a half per cent per year in the coming years, centred on modest economic growth.

Power demand in New York City in 2013 was similar to 2012, primarily due to tepid economic growth conditions and a cool second half of the summer; however, the average New York ISO power price for New York City increased to US$52/MWh in 2013, compared to approximately US$39/MWh in 2012, as a result of higher natural gas prices. The New York ISO forecasts New York City power demand will grow at a rate of 0.5 per cent per year over the next decade, based on modest growth in the population and the economy.

Our northeastern U.S. power facilities also earn significant revenues through participation in regional capacity markets. Capacity markets compensate power suppliers for being available to provide power, and are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. New England ISO's forward capacity market auction prices have been set at US$2.75/kW month for 2014 with prorated prices coming in slightly higher compared to US$2.50/kW month in 2013. In New York, new demand curve parameters were recently set by FERC order to take effect in summer 2014 and have been modestly reduced compared to the parameters presently in place. Combined with other factors affecting the supply and demand for capacity, including the net effect of these new parameters, capacity prices in 2014 are expected to modestly improve over those realized in 2013. For further information on these developments please see Energy Significant Events on page 62.

Capital expenditures

We spent a total of $152 million in 2013, and expect to spend approximately $270 million on capital expenditures in Energy in 2014. See page 82 for further discussion on liquidity risk.

Equity investments and acquisitions

In 2013, we also invested $216 million on the acquisition of four Ontario solar facilities and $63 million in Bruce Power for capital projects. We expect to spend approximately $280 million on the acquisition of the remaining five Ontario solar facilities and $90 million on Bruce Power investments in 2014.

UNDERSTANDING THE ENERGY BUSINESS

Our Energy business is made up of three groups:

- Canadian Power
- U.S. Power
- Natural Gas Storage

Energy comparable EBIT contribution by group, excluding business development expenses
year ended December 31, 2013

Power generation capacity contribution by group
year ended December 31, 2013 (includes facilities in development)

Canadian Power

Western Power

We own or have the rights to approximately 2,600 MW of power supply in Alberta and Arizona through three long-term PPAs, five natural gas-fired cogeneration facilities, and through Coolidge, a simple-cycle, natural gas peaking facility in Arizona.

Power purchased under long-term contracts is as follows:

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

Earnings in the Western Power business are maximized by maintaining and optimizing the operations of our power plants, and through various marketing activities.

A disciplined operational strategy is critical to maximizing output and revenue at our cogeneration facilities and maximizing Coolidge earnings, where revenue is based on plant availability, and is not a function of market price.

The marketing function is critical for optimizing returns and managing risk through direct sales to medium and large industrial and commercial companies and other market participants. Our marketing group sells power sourced through the PPAs, markets uncommitted volumes from the cogeneration plants, and buys and sells power and natural gas to maximize earnings from our assets. To reduce exposure associated with uncontracted volumes, we sell a portion of our power in forward sales markets when acceptable contract terms are available.

A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. This ensures we have adequate power supply to fulfill our sales obligations if we have unexpected plant outages and provides the opportunity to increase earnings in periods of high spot prices.

The amount sold forward will vary depending on market conditions and market liquidity and has historically ranged between 25 to 75 per cent of expected future production with a higher proportion being hedged in the near term periods. Such forward sales may be completed with medium and large industrial and commercial companies and other market participants and will affect our average realized price (versus spot price) in future periods.

Eastern Power

We own or are developing approximately 3,000 MW of power generation capacity in eastern Canada. All of the power produced by these assets is sold under long-term contracts.

Disciplined maintenance of plant operations is critical to the results of our Eastern Power assets, where earnings are based on plant availability and performance.

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

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

1 Power generation has been suspended since 2008.

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

Assets currently in development are as follows:

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

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

Western and Eastern Power results[1,2]

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Revenue			
Western power[1]	**609**	640	822
Eastern power[2]	**400**	415	391
Other[3]	**108**	91	69
	1,117	1,146	1,282
Income from equity investments[4]	**141**	68	117
Commodity purchases resold			
Western power	**(277)**	(281)	(368)
Other[5]	**(6)**	(5)	(9)
	(283)	(286)	(377)
Plant operating costs and other	**(248)**	(218)	(242)
Sundance A PPA arbitration decision 2012	**-**	(30)	-
General, administrative and support costs	**(50)**	(48)	(43)
Comparable EBITDA	**677**	632	737
Comparable depreciation and amortization	**(172)**	(152)	(141)
Comparable EBIT	**505**	480	596
Breakdown of comparable EBITDA			
Western power	**380**	335	483
Eastern power	**347**	345	297
General, administrative and support costs	**(50)**	(48)	(43)
Comparable EBITDA	**677**	632	737

1
Includes Coolidge starting in May 2011.

2
Includes the acquisition of four Ontario Solar facilities in 2013, Cartier phase two of Gros-Morne starting in November 2012, phase one of Gros-Morne starting in November 2011 and Montagne-Sèche starting in November 2011.

3
Includes sale of excess natural gas purchased for generation and sales of thermal carbon black.

4
Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.

5

Includes the cost of excess natural gas not used in operations.

Sales volumes and plant availability[1,2]

Includes our share of volumes from our equity investments.

year ended December 31	2013	2012	2011
Sales volumes (GWh)			
Supply			
Generation			
Western power[1]	**2,728**	2,691	2,606
Eastern power[2]	**3,822**	4,384	3,714
Purchased			
Sundance A & B and Sheerness PPAs[3]	**8,223**	6,906	7,909
Other purchases	**13**	46	248
	14,786	14,027	14,477
Sales			
Contracted			
Western power[1]	**7,864**	8,240	8,381
Eastern power[2]	**3,822**	4,384	3,714
Spot			
Western power	**3,100**	1,403	2,382
	14,786	14,027	14,477
Plant availability [4]			
Western power[1,5]	**95%**	96%	97%
Eastern power[2,6]	**90%**	90%	93%

1 Includes Coolidge starting in May 2011.

2 Includes the acquisition of four Ontario Solar facilities in 2013, Cartier phase two of Gros-Morne starting in November 2012, phase one of Gros-Morne starting in November 2011 and Montagne-Sèche starting in November 2011. Also includes volumes related to our 50 per cent ownership interest in Portlands Energy.

3 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. Sundance A Unit 1 returned to service in early September 2013 and Unit 2 returned to service in early October 2013.

4 The percentage of time in a period that the plant is available to generate power, regardless of whether it is running.

5 Does not include facilities that provide power to us under PPAs.

6 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Western Power's comparable EBITDA in 2013 was $45 million higher than in 2012. The increase was mainly due to increased volumes purchased under the PPAs and sold at realized power prices that were comparable to levels achieved in 2012.

The Alberta power market continued to be strong during 2013. Alberta power demand in 2013 was 2.5 per cent higher than 2012. Average spot market power prices in Alberta were $80/MWh in 2013, or 25 per cent higher than 2012, partly due to three significant long-term coal unit outages, demand growth and higher natural gas prices. Realized power prices on power sales can be higher or lower than spot market power prices in any given period as a result of contracting activities.

Purchased volumes in 2013 were higher than 2012 mainly because of the return to service of the Sundance A Unit 1 in early September 2013 and Unit 2 in early October 2013 and increased volumes under the Sundance B PPA.

Western Power's comparable EBITDA in 2012 was $148 million lower than 2011. This was primarily due to the net effect of:

- the Sundance A force majeure resulting in no earnings recorded in 2012 lower purchased PPA volumes during periods of lower spot prices

incremental earnings from Coolidge, which was placed in service in May 2011

higher realized power prices as a result of contracting activities.

Approximately 72 per cent of Western Power sales volumes were sold under contract in 2013 compared to 85 per cent in 2012 and 78 per cent in 2011.

Eastern Power

Eastern Power's comparable EBITDA in 2013 was similar to 2012, due to the net effect of:

incremental earnings from Cartier and from the four Ontario solar facilities acquired in 2013

lower contractual earnings at Bécancour.

In 2012, Eastern Power's comparable EBITDA was $48 million higher than 2011 mainly due to:

incremental earnings from Cartier

higher contractual earnings at Bécancour.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of Bruce A and Bruce B. Bruce A Units 1 to 4 have a combined capacity of approximately 3,000 MW and Bruce B Units 5 to 8 have a combined capacity of approximately 3,200 MW. Bruce B leases the eight nuclear reactors from Ontario Power Generation and subleases Units 1 to 4 to Bruce A.

Bruce Power's generating capacity is fully contracted with the OPA. Results from Bruce Power fluctuate primarily due to the frequency, scope and duration of planned and unplanned outages.

Under the contract with the OPA, all of the output from Bruce A is sold at a fixed price/MWh. The fixed price is adjusted annually on April 1 for inflation and other provisions under the OPA contract. Bruce A also recovers fuel costs from the OPA.

Bruce A fixed price		**Per MWh**
April 1, 2013	March 31, 2014	$70.99
April 1, 2012	March 31, 2013	$68.23
April 1, 2011	March 31, 2012	$66.33

Under the same contract, all output from Bruce B Units 5 to 8 is subject to a floor price adjusted annually for inflation on April 1.

Bruce B floor price		**Per MWh**
April 1, 2013	March 31, 2014	$52.34
April 1, 2012	March 31, 2013	$51.62
April 1, 2011	March 31, 2012	$50.18

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. Bruce Power has not had to repay any amounts in the past three years.

Bruce B also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price.

Bruce Power results
Our proportionate share

year ended December 31 (millions of $, unless otherwise indicated)	**2013**	**2012**	**2011**
Income/(loss) from equity investments [1]			
Bruce A	**202**	(149)	33
Bruce B	**108**	163	77
	310	14	110
Comprised of:			
Revenues	**1,258**	763	817
Operating expenses	**(618)**	(567)	(565)
Depreciation and other	**(330)**	(182)	(142)
	310	14	110
Bruce Power other information			
Plant availability[2]			
Bruce A[3]	**82%**	54%	90%
Bruce B	**89%**	95%	88%
Combined Bruce Power	**86%**	81%	89%
Planned outage days			
Bruce A	**123**	336	60
Bruce B	**140**	46	135
Unplanned outage days			
Bruce A	**63**	18	16
Bruce B	**20**	25	24
Sales volumes (GWh)[1]			
Bruce A[3]	**10,033**	4,194	5,475
Bruce B	**7,824**	8,475	7,859
	17,857	12,669	13,334
Realized sales price per MWh[4]			
Bruce A	**$70**	$68	$66
Bruce B	**$54**	$55	$54
Combined Bruce Power	**$62**	$57	$57

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. Sales volumes exclude deemed generation.

2 The percentage of time in a year the plant is available to generate power, regardless of whether it is running.

3 Plant availability and sales volumes for 2013 and 2012 include the incremental impact of Unit 1 and Unit 2 which were returned to service in October 2012.

4 Calculation based on actual and deemed generation. Bruce B realized sales prices per MWh includes revenues under the floor price mechanism and revenues from contract settlements.

Equity income from Bruce A in 2013 was $351 million higher than 2012. The increase was mainly due to:

- incremental earnings from Units 1 and 2 which returned to service in October 2012
- higher incremental earnings from Unit 3 due to the West Shift Plus planned outage during first and second quarter 2012
- recognition in first quarter 2013 of an insurance recovery of approximately $40 million related to the May 2012 Unit 2 electrical generator failure that impacted Bruce A in 2012 and 2013
- higher incremental earnings from Unit 4 due to the planned life extension outage which began in third quarter 2012 and was completed in April 2013.

Equity income from Bruce B in 2013 was $55 million lower than 2012. The decrease was mainly due to lower volumes and higher operating costs resulting from higher planned outage days.

In 2012, equity income from Bruce A was $182 million lower than 2011. The decrease was mainly due to lower volumes and higher operating costs resulting from the Unit 4 and the Unit 3 West Shift Plus planned outages, partially offset by incremental earnings from Units 1 and 2 which returned to service in October 2012.

In 2012, equity income from Bruce B was $86 million higher than 2011. The increase was mainly due to higher volumes and lower operating costs resulting from fewer outage days, lower lease expense and higher realized prices.

The overall plant availability percentages in 2014 are expected to be high 80s for both Bruce A and Bruce B. Planned maintenance on a Bruce A unit is scheduled to occur in first half of 2014. Planned maintenance on two Bruce B units is scheduled to occur in first and fourth quarters of 2014.

U.S. Power

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

We earn revenues in both New York and New England in two ways by providing capacity and by selling energy. Capacity markets compensate power suppliers for being available to provide power, and are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. The energy markets compensate power providers for the actual energy they supply.

Providing capacity

Capacity revenues in New York and New England are a function of two factors capacity prices and plant availability. It is important for us to keep our plant availability high to maximize the amount of capacity we get paid for.

Capacity prices paid to capacity suppliers in New York are determined by a series of voluntary forward auctions and a mandatory spot auction. The forward auctions are bid based while the mandatory spot auction is affected by a demand curve price setting process that is driven by a number of established parameters that are subject to periodic review by the New York ISO and FERC. The parameters are determined for each zone and include the forecasted cost of a new unit entering the market, available existing operable supply and fluctuations in the forecasted demand.

The price paid for capacity in the New England Power Pool is determined by annual competitive auctions which are held three years in advance of the applicable capacity year. Auction results are impacted by actual and projected power demand, power supply, and other factors.

Selling energy

We focus on selling power under short and long-term contracts to wholesale, commercial and industrial customers. In some cases, power sales are bundled with other energy services that we earn additional revenues for providing in the following power markets:

- New York, operated by the New York ISO
- New England, operated by the New England ISO
- PJM Interconnection area (PJM).

We meet our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices.

U.S. Power results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information for more details.

year ended December 31 (millions of US$)	**2013**	**2012**	**2011**
Revenue			
Power[1]	**1,484**	1,189	1,139
Capacity	**295**	234	227
Other[2]	**56**	51	80
	1,835	1,474	1,446
Commodity purchases resold	**(1,003)**	(765)	(618)
Plant operating costs and other[2]	**(462)**	(452)	(514)
General, administrative and support costs	**(47)**	(48)	(41)
Comparable EBITDA	**323**	209	273
Comparable depreciation and amortization	**(107)**	(121)	(109)
Comparable EBIT	**216**	88	164

1 The realized gains and losses from financial derivatives used to buy and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in power revenues.

2 Includes revenues and costs related to a third party service agreement at Ravenswood.

Sales volumes and plant availability

year ended December 31	**2013**	**2012**	**2011**
Physical sales volumes (GWh)			
Supply			
Generation	**6,173**	7,567	6,880
Purchased	**9,001**	9,408	6,018
	15,174	16,975	12,898
Plant availability [1]	**84%**	85%	87%

1 The percentage of time in a year the plant is available to generate power, regardless of whether it is running.

U.S. Power's comparable EBITDA in 2013 was US$114 million higher than 2012. This reflected the net effect of:

- higher realized capacity prices in New York
- higher realized power prices partially offset by the impact of higher fuel costs
- higher revenues and certain adjustments on sales to wholesale, commercial and industrial customers.

In 2012, U.S. Power's comparable EBITDA was US$64 million lower than 2011. This reflected the net effect of:

- lower realized power prices
- higher load serving costs and higher sales to wholesale, commercial and industrial customers
- increased generation at the Ravenswood facility offset by reduced water flows at the TC Hydro facilities.

Average New York Zone J spot capacity prices were approximately 38 per cent higher in 2013 than in 2012. The increase in spot prices and the impact of hedging activities resulted in higher realized capacity prices in New York in 2013.

Commodity prices in U.S. Power were higher in 2013 as natural gas prices recovered from low levels in 2012. Higher natural gas prices, fuel transportation constraints in the northeast U.S. and severe weather in both winter 2012/13 and summer 2013 were factors that contributed to an average increase of Independent

System Operator (ISO) power prices in New England of approximately 55 per cent and New York City of approximately 33 per cent in 2013 compared to 2012.

Physical sales volumes in 2013 decreased compared to 2012. Generation volumes decreased primarily due to lower generation at the Ravenswood facility in fourth quarter 2013 compared to fourth quarter 2012, when Ravenswood ran at higher than normal generation levels during and following Superstorm Sandy when damage at several other power and transmission facilities reduced power supply in New York City. Purchased volumes were also lower in 2013 compared to 2012 as volumes purchased to serve the commercial and industrial customers in the New England market decreased offset by higher volumes in the PJM market.

Power revenue and commodity purchases resold were 25 per cent and 31 per cent higher, respectively, in 2013 compared to 2012 mainly due to the higher commodity prices mentioned above.

As at December 31, 2013, approximately 4,300 GWh or 53 per cent of U.S. Power's planned generation is contracted for 2014, and 1,800 GWh or 24 per cent for 2015. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

Natural Gas Storage

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

Storage capacity

year ended December 31, 2013	Working gas storage capacity (Bcf)	Maximum injection/ withdrawal capacity (MMcf/d)
Edson	50	725
CrossAlta	68	550
Third-party storage	38	630
	156	1,905

Our natural gas storage business helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Market volatility creates arbitrage opportunities and our natural gas storage facilities also give customers the ability to capture value from short-term price movements.

The natural gas storage business is affected by the change in seasonal natural gas price spreads, which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons. We manage this exposure by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. We sell a portfolio of short, medium and long-term storage products to participants in the Alberta and interconnected gas markets.

Proprietary natural gas storage transactions include a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, we lock in future positive margins, effectively eliminating our exposure to seasonal natural gas price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair value through net income based on the forward market prices for the contracted month of delivery. We record changes in the fair value of these contracts in revenues. We do not include changes in the fair value of natural gas forward purchase and sales contracts when we calculate comparable earnings, because they do not represent the amounts that will be realized on settlement.

Natural Gas Storage and other results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Natural Gas Storage and other[1]	**73**	77	84
General, administrative and support costs	**(10)**	(10)	(6)
Comparable EBITDA	**63**	67	78
Comparable depreciation and amortization	**(12)**	(10)	(12)
Comparable EBIT	**51**	57	66

1 Includes our share of equity income from our investment in CrossAlta up to December 2012. In December 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent and commenced consolidating their operations.

Comparable EBITDA in 2013 was $4 million lower than 2012, mainly due to lower realized natural gas storage price spreads, partially offset by incremental earnings from CrossAlta resulting from the acquisition of the remaining 40 per cent interest in December 2012.

In 2012, comparable EBITDA was $11 million lower than 2011, mainly due to lower realized natural gas storage price spreads, partially offset by lower operating costs.

SIGNIFICANT EVENTS

Canadian Power

Ontario Solar

In late 2011, we agreed to buy nine Ontario solar generation facilities (combined capacity of 86 MW) from Canadian Solar Solutions Inc., for approximately $500 million. We completed the acquisition of the first facility for $55 million in June 2013, two additional facilities in September 2013 for $99 million, and a fourth facility in December 2013 for $62 million. We expect the acquisition of the remaining five facilities to close in 2014, subject to satisfactory completion of the related construction activities and regulatory approvals. All power produced by the solar facilities is currently or will be sold under 20-year PPAs with the OPA.

Cancarb Limited and Cancarb Waste Heat Facility

On January 20, 2014 we announced we had reached an agreement for the sale of Cancarb Limited, our thermal carbon black facility, and its related power generation facility for $190 million subject to closing adjustments. The sale is expected to close in late first quarter 2014.

Bécancour

In June 2013, Hydro-Québec notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2014. In December 2013, we entered into an amendment to the original suspension agreement with Hydro-Québec to further extend suspension of generation through to the end of 2017. Under the amendment, Hydro-Québec continues to have the option (subject to certain conditions) to further extend the suspension past 2017. The amendment also includes revised provisions intended to reduce Hydro-Québec's payments to us for Bécancour's natural gas transportation costs during the suspension period, although we retain our ability to recover our full capacity costs under the Electricity Supply Contract with Hydro-Québec while the facility is suspended. Final execution of this amendment is conditional on the pending approval by the Régie de l'énergie.

Sundance A

Sundance A Unit 1 returned to service in September 2013 and Sundance A Unit 2 returned to service in October 2013 following an outage that began in December 2010. The operator was ordered by an arbitration panel in July 2012 to rebuild these units.

The revenues and costs recorded in first quarter 2012 from the Sundance A PPA were offset by a second quarter 2012 charge recorded as a result of the July 2012 Sundance A arbitration decision, which determined that the units were in force majeure effective November 2011. We recorded the $50 million charge to second quarter 2012 earnings, of which $20 million related to amounts accrued in 2011. Throughout 2011, revenues and costs had been recorded as though the outages were interruptions of supply in accordance with the terms of the PPA.

Bruce Power

In April 2013, Bruce Power announced that it had reached an agreement with the OPA to extend the Bruce B floor price through to the end of the decade, which is expected to coincide with the 2019 and 2020 end of life dates for the Bruce B units.

Bruce Power returned Bruce A Unit 4 to service in April 2013 after completing an expanded life extension outage investment program, which began in August 2012. It is anticipated that this investment will allow Unit 4 to operate until at least 2021.

On January 31, 2014, Cameco Corporation (Cameco) announced it had agreed to sell its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust (BPC). We are considering our option to increase our Bruce B ownership percentage.

Napanee

In December 2012, we signed a contract with the OPA to develop, own and operate a new 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. The project is on schedule and we expect to complete the permitting process in late 2014. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late 2017 or early 2018.

U.S. Power

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 New York ISO as part of its triennial Demand Curve Reset (DCR) process. The filing changed the generation technology used in the DCR versus that used during the last reset process for New York City Zone J where Ravenswood operates. We do not expect this change to impact Zone J capacity prices in 2014, however, this new assumption does have the potential to negatively affect these capacity prices in 2015 and 2016.

Additionally, another recent FERC decision affecting future capacity auctions in New England Power Pool (NEPOOL) may potentially improve capacity price conditions in 2018 and beyond for our assets that are located in NEPOOL.

BUSINESS RISKS

The following are risks specific to our energy business. See page 76 for information about general risks that affect the company as a whole.

Fluctuating power and natural gas market prices

Power and natural gas prices are affected by fluctuations in supply and demand, weather, and by general economic conditions. The power generation facilities in our Western Power operations in Alberta, and in our U.S. Power operations in New England and New York, are exposed to commodity price volatility. Earnings from these businesses are generally correlated to the prevailing power supply and demand conditions and the price of natural gas, as power prices are usually set by gas-fired power supplies. Extended periods of low gas prices will generally exert downward pressure on power prices and therefore earnings from these facilities. Our Coolidge Generating Station and our portfolio of assets in Eastern Canada are fully contracted, and are therefore not subject to fluctuating commodity prices. Bruce Power's exposure to fluctuating power prices is discussed further below.

To mitigate the impact of power price volatility in Alberta and the U.S. northeast, we sell a portion of our supply under medium to long-term sales contracts where contract terms are acceptable. A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements to ensure we have adequate power supply to fulfill sales obligations if unexpected plant outages occur. This unsold supply is exposed to fluctuating power and natural gas market prices. As power sales contracts expire, new forward contracts are entered into at prevailing market prices.

Under an agreement with the OPA, Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's non-contracted volumes are subject to spot price volatility. When spot prices are below the floor price, Bruce B receives the floor price for all of its output. Bruce B also enters into third party fixed-price contracts where it receives the difference between the contract price and spot price. All Bruce A output is sold into the Ontario wholesale power spot market under a fixed-price contract with the OPA.

Our natural gas storage business is subject to fluctuating seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons.

U.S. Power capacity payments

A significant portion of revenues earned by Ravenswood and a portion of revenues earned by our power facilities in New England are driven by capacity payments. Fluctuations in capacity prices can have a material impact on these businesses, particularly in New York. New York capacity prices are determined by a series of voluntary forward auctions and a mandatory spot auction. The forward auctions are bid based while the mandatory spot auction is affected by a demand curve price setting process that is driven by a number of established parameters that are subject to periodic review by the New York ISO and FERC. These parameters are determined for each capacity zone and include the forecasted cost of a new unit entering the market, available existing operable supply and fluctuations in forecasted demand. Capacity payments are also a function of plant availability which is discussed below.

Plant availability

Optimizing and maintaining plant availability is essential to the continued success of our Energy business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenue and lower capacity payments and margins. We may also have to buy power or natural gas on the spot market to meet our delivery obligations.

We manage this risk by investing in a highly skilled workforce, operating prudently, running comprehensive, risk-based preventive maintenance programs and making effective capital investments.

For facilities we do not operate, our purchase agreements include a financial remedy if a plant owner does not deliver as agreed. The Sundance and Sheerness PPAs, for example, require the producers to pay us market-based penalties if they cannot supply the amount of power we have agreed to purchase.

Regulatory

We operate in both regulated and deregulated power markets in both the United States and Canada. These markets are subject to various federal, state and provincial regulations in both countries. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect us as a generator and marketer of electricity. These may be in the form of market rule changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which negatively affect the price of power or capacity, or both. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Weather

Significant changes in temperature and other weather events have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability.

Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility. Extreme weather can also restrict the availability of natural gas and power if demand is higher than supply.

Seasonal changes in temperature can reduce the efficiency of our natural gas-fired power plants, and the amount of power they produce. Variable wind speeds affect earnings from our wind assets.

Hydrology

Our hydroelectric power generation facilities in the northeastern U.S. are subject to potential hydrology risks that can impact the volume of water available for generation at these facilities including weather changes and events, local river management and potential dam failures at these plants or upstream facilities.

Execution, capital cost and permitting

Energy's construction programs are subject to execution, capital cost and permitting risks.

Corporate

OTHER INCOME STATEMENT ITEMS

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Comparable interest expense	**984**	976	939
Comparable interest income and other	**(42)**	(86)	(60)
Comparable income tax	**662**	477	594
Net income attributable to non-controlling interests	**125**	118	129
Preferred share dividends	**74**	55	55

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Comparable interest on long-term debt			
(including interest on junior subordinated notes)			
Canadian dollar-denominated	**495**	513	490
U.S. dollar-denominated	**766**	740	734
Foreign exchange	**20**	-	(7)
	1,281	1,253	1,217
Other interest and amortization expense	**(10)**	23	24
Capitalized interest	**(287)**	(300)	(302)
Comparable interest expense	**984**	976	939

Comparable interest expense this year was $8 million higher compared to 2012 because of incremental interest on long term debt issues of:

- US$1.25 billion in October 2013
- US$500 million in July 2013
- $750 million in July 2013
- US$500 million in July 2013 by TC PipeLines, LP
- US$750 million in January 2013
- US$1.0 billion in August 2012

as well as higher foreign exchange on interest expense related to U.S. dollar denominated debt, partially offset by Canadian and U.S. dollar denominated debt maturities. In addition, there was a decrease in capitalized interest due to Bruce Units 1 and 2 being placed in service in 2012, partially offset by increased capitalized interest on the Gulf Coast project.

Comparable interest expense in 2012 was $37 million higher than 2011 because of incremental interest on debt issues of:

- US$1.0 billion in August 2012

US$500 million in March 2012

$750 million in November 2011

US$350 million in June 2011 by TC PipeLines, LP.

These increases also reflected the negative impact of a stronger U.S. dollar on U.S. dollar-denominated interest.

Comparable interest income and other was $44 million lower compared to 2012. This decrease was mainly because of losses in 2013 compared to gains in 2012 on the settlement of derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and on translation of foreign denominated working capital balances. In 2012, comparable interest income and other was $26 million higher than 2011 because of higher gains in 2012 on derivatives used to manage exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and on translation of foreign denominated working capital.

Comparable income tax increased $185 million in 2013 compared to 2012 mainly because of higher pre-tax earnings in 2013 compared to 2012 combined with changes in the proportion of income earned between Canadian and foreign jurisdictions. In 2012, comparable income tax decreased $117 million from 2011 because of lower pre-tax earnings.

Net income attributable to non-controlling interests increased in 2013 compared to 2012 primarily due to the sale of a 45 per cent interest in each of GTN LLC and Bison to TC PipeLines, LP in July 2013.

Net income attributable to non-controlling interests decreased in 2012 compared to 2011 because of lower earnings in TC PipeLines, LP mainly due to lower earnings from Great Lakes, partially offset by a full year of earnings from GTN and Bison.

Preferred share dividends increased $19 million in 2013 compared to 2012 because of the issuance of the Series 7 preferred shares in March 2013.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of an economic cycle, and rely on our operating cash flows to sustain our business, pay dividends and fund a portion of our growth.

We believe we have the financial capacity to fund our existing capital program through our predictable cash flow from our operations, access to capital markets, cash on hand and substantial committed credit facilities.

We access capital markets to meet our financing needs, manage our capital structure and to preserve our credit ratings.

Balance sheet analysis

As of December 31, 2013, total assets increased $5.5 billion, total liabilities increased $3.7 billion and total equity rose $1.8 billion compared to December 31, 2012.

The increase in assets is primarily due to increases in property, plant and equipment, intangible and other assets, and equity investments. Property, plant and equipment increased by $3.9 billion primarily due to the construction of the Gulf Coast project, expansion of our Mexican pipelines projects and further investment in the NGTL System. Intangible and other assets rose by $0.5 billion due to the increase in our capital projects under development. Equity investments increased by $0.4 billion primarily due to an increase in our investment in Bruce B.

Capital structure

at December 31 (millions of $)	**2013**	**2012**
Notes payable	**1,842**	2,275
Long-term debt	**22,865**	18,913
Junior subordinated notes	**1,063**	994
Cash and cash equivalents	**(927)**	(551)
Debt, net of cash and cash equivalents	**24,843**	21,631
Equity controlling interests	**18,525**	16,911
Equity non-controlling interests	**1,611**	1,425
Total equity	**20,136**	18,336
	44,979	39,967

In 2013, we issued $4.3 billion and repaid $1.3 billion of long term debt. The strengthening of the U.S. dollar also contributed a $1 billion increase on translation of our U.S. dollar-denominated debt. In 2013, notes payable decreased by $0.4 billion and cash and cash equivalents increased by $0.4 billion.

Total equity increased $1.8 billion in 2013 mainly due to an increase in retained earnings, a $600 million preferred share issuance and a $400 million common unit issuance by TC PipeLines, LP.

Consolidated capital structure

at December 31, 2013

1 Includes non-controlling interests in TC PipeLines, LP and Portland

2 Includes preferred shares of TCPL

3 Net of cash and excluding junior subordinated notes

The following table shows how we have financed our business activities over the last three years. We continue to fund our extensive capital program through cash flow from operations supplemented by capital market financing activity.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Net cash provided by operations	**3,674**	3,571	3,686
Net cash used in investing activities	**(5,120)**	(3,256)	(3,054)
(Deficiency)/surplus	**(1,446)**	315	632
Net cash provided by/(used in) financing activities	**1,794**	(403)	(642)
	348	(88)	(10)

Liquidity will continue to be comprised of predictable cash flow generated from operations, committed credit facilities, our ability to access debt and equity markets in both Canada and the U.S., and portfolio management including additional drop downs of assets into TC PipeLines, LP.

As at December 31, 2013, we were in compliance with all of our financial covenants. Provisions of various trust indentures and credit arrangements that certain of our subsidiaries are party to restrict those subsidiaries' ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends on our common and preferred shares. In the opinion of management, these provisions do not currently restrict or alter our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios.

Net cash provided by operations

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Funds generated from operations	**4,000**	3,284	3,451
(Increase)/decrease in operating working capital	**(326)**	287	235
Net cash provided by operations	**3,674**	3,571	3,686

Funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations, excluding the timing effects of working capital changes. See page 15 for more information about non-GAAP measures.

At December 31, 2013, our current liabilities were higher than our current assets, leaving us with a working capital deficit of $2.2 billion. This short-term deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate cash flow from operations
- our access to North American capital markets
- approximately $5 billion of unutilized committed revolving bank lines.

Net cash used in investing activities

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Capital expenditures	**4,461**	2,595	2,513
Other investing activities	**659**	661	541

Our 2013 capital expenditures were incurred primarily for construction of the Gulf Coast project, expanding our NGTL System and construction of our Mexican pipelines. Other investing activities in 2013 included the acquisitions of four solar facilities from Canadian Solar Solutions Inc.

We are developing quality projects under our long-term $38 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements and once completed, are expected to generate significant growth in earnings and cashflow.

Our $38 billion capital program is comprised of $12 billion of small to medium-sized projects and $26 billion of large scale projects each of which are subject to key commercial or regulatory approvals. The portfolio is expected to be financed through our growing internally generated cash flow and a combination of funding options including:

- senior debt
- preferred shares
- hybrid securities
- portfolio management including additional drop downs to TC PipeLines, LP or asset sales

potential involvement of strategic or financial partners.

Additional financing alternatives available include common equity through DRP or lastly, discrete equity issuances.

Net cash provided by/(used in) financing activities

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Long-term debt issued, net of issue costs	**4,253**	1,491	1,622
Long-term debt repaid	**(1,286)**	(980)	(1,272)
Notes payable (repaid)/issued, net	**(492)**	449	(224)
Dividends and distributions paid	**(1,522)**	(1,416)	(1,147)
Common shares issued	**72**	53	58
Preferred shares issued, net of issue costs	**585**	-	-
Partnership units of subsidiary issued, net of issue costs	**384**	-	321
Preferred shares of subsidiary redeemed	**(200)**	-	-

Long-term debt issued:

US$750 million of senior unsecured notes, maturing on January 15, 2016 and bearing interest at 0.75 per cent per annum, in January 2013

US$500 million of three-year London Interbank Offered Rate-based floating rate notes maturing on June 30, 2016, bearing interest at an initial annual rate of 0.95 per cent, in July 2013

$450 million of ten-year medium term notes maturing on July 19, 2023, bearing interest at 3.69 per cent per annum, in July 2013

$300 million of 30-year medium term notes maturing November 15, 2041, bearing interest at 4.55 per cent per annum, in July 2013

US$625 million of senior unsecured notes, maturing on October 16, 2023 and bearing interest at 3.75 per cent per annum, in October 2013

US$625 million of senior unsecured notes, maturing on October 16, 2043 and bearing interest at 5.0 per cent per annum, in October 2013.

Long-term debt retired:

US$350 million of 4.00 per cent senior unsecured notes, in June 2013

US$500 million of 5.05 per cent senior unsecured notes, in August 2013.

In March 2013, we completed a public offering of 24 million Series 7 cumulative redeemable first preferred shares at a price of $25 per share for aggregate gross proceeds of $600 million. Investors will be entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly. Investors will have the right to convert their shares into cumulative redeemable first preferred shares, Series 8, every fifth year beginning on April 30, 2019. The holders of Series 8 shares will be entitled to receive quarterly floating rate cumulative dividends at an annualized rate equal to the then 90-day Government of Canada treasury bill rate plus 2.38 per cent.

In October 2013, we redeemed four million outstanding 5.60 per cent Cumulative Redeemable First Preferred Shares Series U of TCPL. The Series U Shares were redeemed at a price of $50 per share plus $0.5907 of accrued and unpaid dividends. The total face value of the outstanding Series U Shares was $200 million and carried an aggregate of $11 million in annualized dividends.

In January 2014, we completed a public offering of Series 9 preferred shares for gross proceeds of $450 million, reducing the capacity under our equity shelf prospectus to $1.55 billion. Investors will be entitled to receive fixed cumulative dividends at an annual rate of $1.0625 per share, payable quarterly. Investors will have the right to convert their shares into cumulative redeemable first preferred shares, Series 10, every fifth year beginning on October 30, 2019. The holders of Series 10 shares will be entitled to receive quarterly floating rate cumulative dividends at an annualized rate equal to the then 90-day Government of Canada treasury bill rate plus 2.35 per cent.

In January 2014, we announced the redemption of Series Y preferred shares of TCPL at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends. The total face value of the outstanding Series Y Shares was $200 million and carried an aggregate of $11 million in annualized dividends.

The net proceeds of the above offerings were used for general corporate purposes and to reduce short-term indebtedness.

In May 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at US$43.85 per common unit for gross proceeds of US$388 million. We contributed an additional approximate US$8 million to maintain our general partnership interest and did not purchase any other units. Upon completion of this offering, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent.

In July 2013, TC PipeLines, LP entered into a five-year, US$500 million medium-term loan, maturing July 2018. The proceeds from the public offering, term loan and partner contribution were used to finance the acquisition of the 45 per cent interest in GTN and Bison from us.

As at December 31, 2013, we had unused capacity of $2.0 billion, $2.0 billion and US$4.0 billion under our equity, Canadian debt and U.S. debt shelf prospectuses to facilitate future access to the North American debt and equity markets.

Credit facilities

We have committed, revolving credit facilities to primarily support our commercial paper programs. The commercial paper programs, along with additional demand credit facilities are used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At December 31, 2013, we had $6.2 billion (2012 $5.3 billion) in unsecured credit facilities, including:

Amount	Unused capacity	Subsidiary	For	Matures
$3.0 billion	$3.0 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program	December 2018
US$1.0 billion	US$0.8 billion	TransCanada PipeLine USA Ltd. (TCPL USA)	Committed, syndicated, revolving extendible credit facility that is used for TCPL USA general corporate purposes	November 2014
US$1.0 billion	US$1.0 billion	TransCanada American Investments Ltd. (TAIL)	Committed, syndicated, revolving, extendible credit facility that supports the TAIL U.S. dollar commercial paper program in the U.S.	November 2014
$1.1 billion	$0.3 billion	TCPL / TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At December 31, 2013, we had outstanding $0.7 billion in letters of credit under these lines	Demand

At December 31, 2013, our operated affiliates had $0.3 billion of undrawn capacity on committed credit facilities.

Contractual obligations
Payments due (by period)

at December 31, 2013 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Notes payable	1,842	1,842	-	-	-
Long-term debt (includes junior subordinated notes)	23,928	973	3,751	2,494	16,710
Operating leases (future annual payments for various premises, services and equipment, less sub-lease receipts)	752	90	177	160	325
Purchase obligations	8,187	3,134	2,914	1,068	1,071
Other long-term liabilities reflected on the balance sheet	386	8	16	18	344
	35,095	6,047	6,858	3,740	18,450

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee retirement and post-retirement benefit plans.

Long-term debt
At the end of 2013, we had $22.9 billion of long-term debt and $1.1 billion of junior subordinated notes, compared to $18.9 billion of long-term debt and $1.0 billion of junior subordinated notes at December 31, 2012.

Total notes payable were $1.8 billion at the end of 2013 compared to $2.3 billion at the end of 2012.

We attempt to spread out the maturity profile of our debt. The majority of our obligations mature beyond five years with an average term of 12 years.

At December 31, 2013, scheduled principal repayments and interest payments related to long-term debt were as follows:

Principal repayments
Payments due (by period)

at December 31, 2013 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Notes payable	1,842	1,842	-	-	-
Long-term debt	22,865	973	3,751	2,494	15,647
Junior subordinated notes	1,063	-	-	-	1,063
	25,770	2,815	3,751	2,494	16,710

Interest payments
Payments due (by period)

at December 31, 2013 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months

Long-term debt	16,798	1,254	2,315	2,111	11,118
Junior subordinated notes	3,614	68	135	135	3,276
	20,412	1,322	2,450	2,246	14,394

Operating leases

Our operating leases for premises, services and equipment expire at different times between now and 2052. Some of our operating leases include the option to renew the agreement for one to 10 years.

Our commitments under the Alberta PPAs are considered operating leases. Future payments under these PPAs depend on plant availability, so we do not include them in our summary of future obligations. Our share of power purchased under the PPAs in 2013 was $242 million (2012 $238 million; 2011 $309 million).

We have subleased a part of the PPAs to third parties under terms and conditions similar to our own leases.

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements.

Capital expenditure commitments include signed contracts related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

Payments due (by period)

(not including pension plan contributions)

at December 31, 2013 (millions of $)	**Total**	**less than 12 months**	**12 - 36 months**	**37 - 60 months**	**more than 60 months**
Natural Gas Pipelines					
Transportation by others[1]	463	134	173	133	23
Capital expenditures[2,3]	1,252	845	407	-	-
Other	13	7	4	2	-
Oil Pipelines					
Capital expenditures[2,4]	2,537	1,223	1,188	126	-
Other	70	7	14	14	35
Energy					
Commodity purchases[5]	2,568	496	929	655	488
Capital expenditures[2,6]	120	47	60	13	-
Other[7]	1,140	353	137	125	525
Corporate					
Information technology and other	24	22	2	-	-
	8,187	3,134	2,914	1,068	1,071

1 Rates are primarily based on known 2013 levels. Demand rates may change after 2013. Purchase obligations are based on known or contracted demand volumes only and do not include commodity charges incurred when volumes flow.

2 Amounts are estimates and can vary depending on timing of construction and project enhancements. We expect to fund capital projects with cash from operations, by issuing senior debt and subordinated capital, if required, and through portfolio management.

3 Primarily relate to the construction costs of the NGTL System expansion and the Mexican pipeline projects.

4 Primarily relate to Keystone XL and Grand Rapids.

5 Includes fixed and variable components but does not include derivatives. The variable components are estimates and can vary depending on plant production, market prices and regulatory tariffs.

6 Primarily relate to preliminary construction and development costs of Napanee.

7 Includes estimates of certain amounts that may change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries and changes in regulated rates for transportation. This also includes the remaining purchase obligations for Ontario Solar.

KEY PURCHASE COMMITMENTS

Ontario Solar

In December 2011, we announced an agreement to purchase nine solar facilities in Ontario with a combined capacity of 86 MW at a cost of approximately $500 million. To date, we have purchased four of the nine solar facilities at a cost of $216 million, with the expectation to acquire the remaining facilities in 2014.

GUARANTEES

Bruce Power

We and our partners, Cameco and BPC, have severally guaranteed one-third of some of Bruce B's contingent financial obligations related to power sales agreements, a lease agreement and contractor services. The Bruce B guarantees have terms to 2018 except for one guarantee with no termination date that has no exposure associated with it.

We and BPC have each severally guaranteed half of certain contingent financial obligations of Bruce A related to a sublease agreement, an agreement with the OPA to restart the Bruce A power generation units, and certain other financial obligations. The Bruce A guarantees have terms to 2019.

At December 31, 2013, our share of the potential exposure under the Bruce A and B guarantees was estimated to be $629 million. The carrying amount of these guarantees was estimated to be $8 million. Our exposure under certain of these guarantees is unlimited.

Other jointly owned entities

We and our partners in certain other jointly owned entities have also guaranteed (jointly, severally, or jointly and severally) the financial performance of these entities relating mainly to redelivery of natural gas, PPA payments and the payment of liabilities. The guarantees have terms ranging from 2014 to 2040.

Our share of the potential exposure under these assurances was estimated at December 31, 2013 to be a maximum of $51 million. The carrying amount of these guarantees was $10 million, and is included in other long-term liabilities. In some cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS   PENSION AND OTHER POST-RETIREMENT PLANS

In 2014, we expect to make funding contributions of approximately $70 million for the defined benefit pension plans, approximately $6 million for the other post-retirement benefit plans and approximately $34 million for the savings plan and defined contribution pension plans. We also expect to provide a $47 million letter of credit to our Canadian defined benefit plan in lieu of cash funding.

In 2013, we made funding contributions of $79 million to our defined benefit pension plans, $6 million for the other post-retirement benefit plans and $29 million for the savings plan and defined contribution pension plans. We also provided a $59 million letter of credit to a defined benefit plan in lieu of cash funding.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2015. Based on current market conditions, we expect funding requirements for these plans to approximate 2013 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

Our net benefit cost for our defined benefit and other post-retirement plans increased to $134 million in 2013 from $99 million, mainly due to a lower discount rate used to measure the benefit obligation.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors, including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity.

Other information

RISKS AND RISK MANAGEMENT

The following is a summary of general risks that affect our company. You can find risks specific to each operating business segment in the business segment discussions.

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are in line with our business objectives and risk tolerance.

We build risk assessment into our decision-making processes at all levels.

The Board's Governance Committee oversees our risk management activities, including making sure there are appropriate management systems in place to manage our risks, and adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk: the Audit Committee oversees management's role in monitoring financial risk, the Human Resources Committee oversees executive resourcing and compensation, organizational capabilities and compensation risk, and the Health, Safety and Environment Committee oversees operational, safety and environmental risk through regular reporting from management.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation.

Operational risks

Business interruption

Operational risks, including labour disputes, equipment malfunctions or breakdowns, acts of terror, or natural disasters and other catastrophic events, could decrease revenues, increase costs or result in legal or other expenses, all of which could reduce our earnings. We have incident, emergency and crisis management systems to ensure an effective response to minimize further loss or injuries and to enhance our ability to resume operations. We have comprehensive insurance to mitigate certain of these risks, but insurance does not cover all events in all circumstances. Losses that are not covered by insurance may have an adverse effect on our operations, earnings, cash flow and financial position.

Our reputation and relationships

Stakeholders, such as Aboriginal communities, other communities, landowners, governments and government agencies, and environmental non-governmental organizations can have a significant impact on our operations, infrastructure development and overall reputation. Our Stakeholder Engagement Framework which we have implemented across the company is our formal commitment to stakeholder engagement. Our four core values integrity, collaboration, responsibility and innovation are at the heart of our commitment to stakeholder engagement, and guide us in our interactions with stakeholders.

Execution and capital costs

Investing in large infrastructure projects involves substantial capital commitments, based on the assumption that these assets will deliver an attractive return on investment in the future. Under some contracts, we share the cost of these risks with customers, in exchange for the potential benefit they will realize when the project is finished. While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost overrun risk which may decrease our return on these projects.

Cyber security

Security threats, including cyber security threats, and related disruptions can have a negative impact on our business. We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.

Pipeline abandonment costs

The NEB's Land Matters Consultation Initiative (LMCI) is an initiative that will require all Canadian pipeline companies regulated by the NEB to set aside funds to cover future abandonment costs.

The NEB provided several key guiding principles during the LMCI process, including the position that abandonment costs are a legitimate cost of providing pipeline service and are recoverable, upon NEB approval, from users of the individual pipeline systems. The first hearing addressing the basis and the approach to the determination of specific pipeline abandonment cost estimates was held in October 2012. Additional hearings and the Board's decisions are scheduled to be completed by June 2014. We do not expect the collection of funds to begin until 2015 at the earliest.

Health, safety and environment

Our approach to managing health and safety and protecting the environment is guided by our HSE commitment statement, which outlines guiding principles for a safe and healthy environment for our employees, contractors and the public, and expresses our commitment to protect the environment.

We are committed to continually improving our occupational health and safety performance, and to promoting safety on and off the job, in the belief that all occupational injuries and illnesses are preventable. We strive to work with companies and contractors who share our commitment and approach. We also have environmental controls in place, including physical design, programs, procedures and processes, to help manage the environmental risk factors we are exposed to, including spills and releases.

Management monitors HSE performance and is kept informed about operational issues and initiatives through formal incident and issues management processes and regular reporting.

The safety and integrity of our existing and newly-developed infrastructure is also a top priority. All 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. We spent $376 million in 2013 for pipeline integrity on the pipelines we operate, an increase of $67 million over 2012 primarily due to increased levels of in-line pipeline inspection on all systems as well an increased amount of pipe replacement required due to population encroachment on the pipelines. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB-regulated pipelines are generally treated on a flow-through basis and, as a result, these expenditures have minimal impact on our earnings. Under the Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures have no impact on our earnings. Our safety record in 2013 continued to exceed industry benchmarks.

Spending associated with public safety on Energy assets is focused primarily on our hydro dams and associated equipment.

Our main environmental risks are:

- air and greenhouse gas (GHG) emissions
- product releases, including crude oil and natural gas, into the environment (land, water and air)
- use, storage and disposal of chemicals and hazardous materials
- compliance with corporate and regulatory policies and requirements.

As described in the Business interruption section, above, we have a set of procedures in place to manage our response to natural disasters and other catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in the Operating Procedures in our Incident Management System, are designed to help protect the health and safety of our employees, minimize risk to the public and limit the impact any operational issues caused by a natural disaster might have on the environment.

Environmental compliance and liabilities

Our facilities are subject to stringent federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, wastewater discharges and waste management. Our facilities are required to obtain and comply with a wide variety of environmental registrations, licences, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements or orders for future operations.

We continually monitor our facilities to ensure compliance with all environmental requirements. We routinely monitor proposed changes in environmental policy, legislation and regulation, and where the risks are potentially large or uncertain, we comment on proposals independently or through industry associations.

We are not aware of any material outstanding orders, claims or lawsuits related to releasing or discharging any material into the environment or in connection with environmental protection.

Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations.

Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties.

It is not possible to estimate the amount and timing of all our future expenditures related to environmental matters because:

- environmental laws and regulations (and interpretation and enforcement of them) can change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean up cost estimates may change, especially when our current estimates are based on preliminary site investigation or agreements
- we may find new contaminated sites, or what we know about existing sites could change
- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2013, we had accrued approximately $32 million related to these obligations ($37 million at the end of 2012). This represents the amount that we have estimated that we will need to manage our currently known environmental liabilities. We believe that we have considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, there is the risk that unforeseen matters may arise requiring us to set aside additional amounts. We adjust this reserve quarterly to account for changes in liabilities.

Greenhouse gas emissions regulation risk

We own assets and have business interests in a number of regions where there are regulations to address industrial GHG emissions. We have procedures in place to comply with these regulations, including:

- under the Specified Gas Emitters Regulation in Alberta, established industrial facilities with GHG emissions above a certain threshold have had to reduce their emissions by 12 per cent below an average intensity baseline since 2007. Our NGTL System facilities and Sundance and Sheerness are subject to this regulation. We recover compliance costs on the NGTL System through the tolls our customers pay. A portion of the compliance costs for Sundance and Sheerness are recovered through market pricing and contract flow through provisions. We recorded $25 million for the Alberta Specified Gas Emitters Regulation in 2013 (2012 $15 million)
- B.C. has imposed a tax on carbon dioxide (CO_2) emissions from fossil fuel combustion since 2008. We recover the compliance costs for our compressor and meter stations through the tolls our customers pay. In 2013, we recorded $6 million (2012 $5 million) for the B.C. carbon tax

Northeastern U.S. states that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap-and-trade program for electricity generators beginning January 2009. This program applies to both the Ravenswood and Ocean State Power generation facilities. We recorded $6 million in 2013 (2012 $3 million) to participate in quarterly auctions of allowances under RGGI

Québec's *Regulation Respecting a Cap-and-Trade System for Greenhouse Gas Emission Allowances* came into force in December 2011 with significant amendments finalized on December 2012. Beginning in January 2013, Bécancour was required to cover its GHG emissions. As per the regulations, the government awarded free emission units for the majority of Bécancour's compliance requirements for 2013. The remaining were purchased through an auction. The pipeline facilities in Québec are also covered under this regulation and have purchased compliance instruments. We recorded less than $1 million for compliance with this regulation

in 2013, California implemented a cap and trade program that impacts electricity importers as well as a number of industrial emitters of GHG emissions. Our costs associated with the program were less than $1 million.

There are federal, regional, state and provincial initiatives currently in development. While economic events may continue to affect the scope and timing of new regulations, we anticipate that most of our facilities will be subject to future regulations to manage industrial GHG emissions.

Financial risks

We are exposed to market risk, counterparty credit risk and liquidity risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value.

These strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. We manage market risk and counterparty credit risk within limits that are ultimately established by the Board, implemented by senior management and monitored by our risk management and internal audit groups. Management monitors compliance with market and counterparty risk management policies and procedures, and reviews the adequacy of the risk management framework, overseen by the Audit Committee. Our internal audit group assists the Audit Committee by carrying out regular and ad-hoc reviews of risk management controls and procedures, and reporting up to the Audit Committee.

Market risk

We build and invest in large infrastructure projects, buy and sell energy commodities, issue short-term and long-term debt (including amounts in foreign currencies) and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices and foreign exchange and interest rates which may affect our earnings and the value of the financial instruments we hold.

We use derivative contracts to assist in managing our exposure to market risk, including:

forwards and futures contracts agreements to buy or sell a financial instrument or commodity at a specified price and date in the future. We use foreign exchange and commodity forwards and futures to manage the impact of changes in foreign exchange rates and commodity prices

swaps agreements between two parties to exchange streams of payments over time according to specified terms. We use interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices

options agreements that give the purchaser the right (but not the obligation) to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. We use option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

We assess contracts we use to manage market risk to determine whether all, or a portion of it, meets the definition of a derivative.

Commodity price risk

We are exposed to changes in commodity prices, especially electricity and natural gas, which may affect our earnings. We use several strategies to reduce this exposure, including:

- committing a portion of expected power supply to fixed price sales contracts of varying terms while reserving a portion of our unsold power supply to mitigate operational and price risk in our asset portfolio
- purchasing a portion of the natural gas we need to fuel our natural gas-fired power plants in advance or entering into contracts that base the sale price of our electricity on the cost of the natural gas, effectively locking in a margin
- meeting our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices
- using derivative instruments to enter into offsetting or back-to-back positions to manage commodity price risk created by certain fixed and variable prices in arrangements for different pricing indices and delivery points.

Foreign exchange and interest rate risk

Certain of our businesses generate income in U.S. dollars, but since we report in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, our exposure to changes in currency rates increases. Some of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We have floating interest rate debt which subjects us to interest rate cash flow risk. We manage this using a combination of interest rate swaps and options.

Average exchange rate U.S. to Canadian dollars

2013	1.03
2012	1.00
2011	0.99

The impact of changes in the value of the U.S. dollar on our U.S. operations is significantly offset by other U.S. dollar-denominated items, as set out in the table below. Comparable EBIT is a non-GAAP measure. See page 15 for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2013**	**2012**	**2011**
U.S. and International Natural Gas Pipelines comparable EBIT	**542**	660	761
U.S. Oil Pipelines comparable EBIT	**389**	363	301
U.S. Power comparable EBIT	**216**	88	164
Interest on U.S. dollar-denominated long-term debt	**(766)**	(740)	(734)
Capitalized interest on U.S. dollar-denominated capital expenditures	**219**	124	116
U.S. non-controlling interests and other	**(196)**	(192)	(192)
	404	303	416

We hedge our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options.

Derivatives designated as a net investment hedge

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

	2013		2012	
at December 31 (millions of $)	**Fair value[1]**	**Notional or principal amount**	**Fair value[1]**	**Notional or principal amount**
U.S. dollar cross-currency interest rate swaps (maturing 2014 to 2019)[2]	**(201)**	**US 3,800**	82	US 3,800
U.S. dollar foreign exchange forward contracts (maturing 2014)	**(11)**	**US 850**	-	US 250
	(212)	**US 4,650**	82	US 4,050

1 Fair values equal carrying values.

2 Consolidated net income in 2013 included net realized gains of $29 million (2012 gains of $30 million) related to the interest component of cross-currency swap settlements.

U.S. dollar-denominated debt designated as a net investment hedge

at December 31 (millions of $)	**2013**	**2012**
Carrying value	**14,200**	11,100
	(US 13,400)	(US 11,200)
Fair value	**16,000**	14,300
	(US 15,000)	(US 14,400)

The balance sheet classification of the fair value of derivatives used to hedge our U.S. dollar net investment in foreign operations is as follows:

at December 31 (millions of $)	**2013**	**2012**
Other current assets	**5**	71
Intangible and other assets	**-**	47
Accounts payable and other	**(50)**	(6)
Other long-term liabilities	**(167)**	(30)
	(212)	82

Counterparty credit risk

We have exposure to counterparty credit risk in the following areas:

- accounts receivable
- portfolio investments
- the fair value of derivative assets
- notes receivable.

If a counterparty fails to meet its financial obligations to us according to the terms and conditions of the financial instrument, we could experience a financial loss. We manage our exposure to this potential loss using recognized credit management techniques, including:

- dealing with creditworthy counterparties a significant amount of our credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- setting limits on the amount we can transact with any one counterparty we monitor and manage the concentration of risk exposure with any one counterparty, and reduce our exposure when we feel we need to and when it is allowed under the terms of our contracts

using contract netting arrangements and obtaining financial assurances, such as guarantees and letters of credit or cash, when we believe it is necessary.

There is no guarantee, however, these techniques will protect us from material losses.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. We had no significant credit losses in 2013 and no significant amounts past due or impaired at year end. We had a credit risk concentration of $240 million at December 31, 2013 with one counterparty ($259 million in 2012). This amount is secured by a guarantee from the counterparty's parent company and we anticipate collecting the full amount.

We have significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity by continuously forecasting our cash flow for a 12 month period and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

See page 67 for more information about our financial condition.

Dealing with legal proceedings

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

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

We carried out an evaluation under the supervision and with the participation of management, including our President and CEO and our CFO, of the effectiveness of our disclosure controls and procedures as at December 31, 2013 as required by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, our President and CEO and our CFO have concluded that the disclosure controls and procedures are effective in that they are designed to ensure that the information we are required to disclose in reports we file with or send to securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.

Management's annual report on internal control over financial reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, our President and CEO and our CFO, and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including our President and CEO and our CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2013 based on the criteria described in "Internal Control Integrated Framework" issued in

1992 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2013, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2013 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included herein.

Limitations of the effectiveness of controls

Management's assessment included an evaluation of the design and testing of the operational effectiveness of internal control over financial reporting. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in internal control over financial reporting

There has been no change in our internal control over financial reporting that occurred during the year ended December 31, 2013, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Effective January 1, 2014, management implemented an Enterprise Resource Planning (ERP) system, which had no impact on our internal control over financial reporting at December 31, 2013. As a result of the ERP system, certain processes supporting our internal control over financial reporting are expected to change in 2014. Management will continue to monitor these processes going forward.

CEO AND CFO CERTIFICATIONS

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2013 reports filed with Canadian securities regulators and the SEC, and have filed certifications with them.

CRITICAL ACCOUNTING ESTIMATES

When we prepare financial statements that conform with GAAP, we are required to make certain estimates and assumptions that affect the timing and amount we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgment. We also regularly assess the assets and liabilities themselves.

The following accounting estimates require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements.

Rate-regulated accounting

Under GAAP, a company qualifies to use rate-regulated accounting (RRA) when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct and indirect competition.

We believe that the regulated natural gas pipelines we account for using RRA meet these criteria. The most significant impact of using these principles is the timing of when we recognize certain expenses and revenues, which is based on the economic impact of the regulators' decisions about our revenues and tolls, and may be different from what would otherwise be expected under GAAP. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods. Regulatory liabilities are amounts that are expected to be refunded through customer rates in future periods.

Regulatory assets and liabilities

at December 31 (millions of $)	**2013**	**2012**
Regulatory assets		
Long-term assets	**1,735**	1,629
Short-term assets (included in other current assets)	**42**	178
Regulatory liabilities		
Long-term liabilities	**229**	268
Short-term liabilities (included in accounts payable and other)	**7**	100

Impairment of long-lived assets and goodwill

We review long-lived assets (such as plant, property and equipment) and intangible assets for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. If the total of the undiscounted future cash flows we estimate for an asset is less than its carrying value, we consider its fair value to be less than its carrying value, and we calculate an impairment loss to recognize this.

Goodwill

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and if we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we use a two-step process to test for impairment:

1. First, we compare the fair value of the reporting unit, including its goodwill, to its book value. If fair value is less than book value, we consider our goodwill to be impaired.

2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting units from the fair value we calculated in the first step. If the goodwill's carrying value exceeds its implied fair value, we record an impairment charge.

We base these valuations on our projections of future cash flows, which involves making estimates and assumptions about:

- discount rates
- commodity and capacity prices
- market supply and demand assumptions
- growth opportunities
- output levels
- competition from other companies
- regulatory changes.

If our assumptions change significantly, our requirement to record an impairment charge could also change. There is a risk that adverse changes in key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. These assumptions could be negatively impacted by factors including changes in customer demand at Great Lakes for pipeline capacity and services, weather, levels of natural gas in storage, and regulatory decisions. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$266 million at December 31, 2013 (2012 US$266 million).

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Asset retirement obligations

When there is a legal obligation to set aside funds to cover future abandonment costs, and we can reasonably estimate them, we recognize the fair value of the asset retirement obligation (ARO) in our financial statements.

We cannot determine when we will retire many of our hydro-electric power plants, oil pipelines, natural gas pipelines and transportation facilities and regulated natural gas storage systems because we intend to operate them as long as there is supply and demand, and so we have not recorded obligations for them.

For those we do record, we use the following assumptions:

- when we expect to retire the asset
- the scope of abandonment and reclamation activities that are required
- inflation and discount rates.

The ARO is initially recorded when the obligation exists and is subsequently accreted through charges to operating expenses.

We continue to evaluate our future abandonment obligations and costs and monitor developments that could affect the amounts we record.

Canadian regulated pipelines

The NEB's LMCI is an initiative for all pipeline companies regulated under the *National Energy Board Act* (Canada) to begin collecting and setting aside funds to cover future abandonment costs.

As part of the guidance provided by the initiative, the NEB has stated that abandonment costs are a legitimate cost of providing pipeline service and should be recoverable (with NEB approval) from system users.

In May 2009, the NEB established several filing deadlines for pipeline companies, including deadlines for

- estimating their pipeline abandonment costs
- proposing how they will collect these funds (through tolls or another satisfactory method)
- proposing how they will set aside the funds they collect.

We filed estimates for our regulated Canadian oil and natural gas pipelines in November 2011 as required. In February 2013, the NEB issued its Reasons for Decision regarding pipeline abandonment cost estimates. We filed revisions to our estimates in April 2013 and January 2014. In February and April 2013, we filed our set-aside and collection mechanism applications. An oral hearing to consider both applications commenced on January 14, 2014. Based on the NEB's direction in 2009, the earliest we could begin collecting funds through cost of service tolls would be 2015. The specific impacts on tolls will depend on the 2014 proceeding related to the collection mechanism.

FINANCIAL INSTRUMENTS

All financial instruments, including both derivative and non-derivative instruments, are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchases and normal sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of our notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of long-term debt has been estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data providers. The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Certain non-derivative financial instruments including cash and cash equivalents, accounts receivable, intangibles and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that equal their fair value due to the nature of the item or the short time to maturity.

Contractual maturities of non-derivative liabilities

The following tables detail the remaining contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows:

Contractual principal repayments of non-derivative financial liabilities

at December 31, 2013 (millions of $)	**Total**	**2014**	**2015 and 2016**	**2017 and 2018**	**2019 and thereafter**
Notes payable	1,842	1,842	-	-	-
Long-term debt	22,865	973	3,751	2,494	15,647
Junior subordinated notes	1,063	-	-	-	1,063
	25,770	2,815	3,751	2,494	16,710

Interest payments on non-derivative financial liabilities

at December 31, 2013 (millions of $)	**Total**	**2014**	**2015 and 2016**	**2017 and 2018**	**2019 and thereafter**
Long-term debt	16,798	1,254	2,315	2,111	11,118
Junior subordinated notes	3,614	68	135	135	3,276
	20,412	1,322	2,450	2,246	14,394

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We apply hedge accounting to derivative instruments that qualify. The effective portion of the change in the fair value of hedging derivatives for cash flow hedges and hedges of our net investment in foreign operations are recorded in other comprehensive income (OCI) in the period of change. Any ineffective portion is recognized in net income in the same financial category as the underlying transaction. The change in the fair value of derivative instruments that have been designated as fair value hedges are recorded in net income in interest income and other and interest expense.

Derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk (held for trading). Changes in the fair

value of held for trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held for trading derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on the derivatives for the Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives have been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of the derivative instruments is as follows:

at December 31 (millions of $)	**2013**	**2012**
Other current assets	**395**	259
Intangible and other assets	**112**	187
Accounts payable and other	**(357)**	(283)
Other long-term liabilities	**(255)**	(186)
	(105)	(23)

Anticipated timing of settlement   derivative instruments

The anticipated timing of settlement for derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates. Settlements will vary based on the actual value of these factors at the date of settlement.

at December 31, 2013 (millions of $)	**Total fair value**	**2014**	**2015 and 2016**	**2017 and 2018**
Derivative instruments held for trading				
Assets	346	268	74	4
Liabilities	(371)	(288)	(81)	(2)
Derivative instruments in hedging relationships				
Assets	161	128	33	-
Liabilities	(241)	(70)	(143)	(28)
	(105)	38	(117)	(26)

The effect of derivative instruments on the consolidated statement of income

The following summary does not include hedges of our net investment in foreign operations.

year ended December 31 (millions of $)	2013	2012
Derivative instruments held for trading[1]		
Amount of unrealized gains/(losses) in the year		
Power	**19**	(30)
Natural gas	**17**	2
Foreign exchange	**(10)**	(1)
Amount of realized (losses)/gains in the year		
Power	**(49)**	5
Natural gas	**(13)**	(10)
Foreign exchange	**(9)**	26
Derivative instruments in hedging relationships[2,3]		
Amount of realized (losses)/gains in the year		
Power	**(19)**	(130)
Natural gas	**(2)**	(23)
Interest	**5**	7

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in energy revenues. Realized and unrealized gains and losses on interest rate and foreign exchange held for trading derivative instruments are included net in interest expense and interest income and other, respectively.

2 At December 31, 2013 all hedging relationships were designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $5 million (2012 $10 million) and a notional amount of US$200 million (2012 US$350 million). In 2013, net realized gains on fair value hedges were $6 million (2012 $7 million) and were included in interest expense. In 2013 and 2012, we did not record any amounts in net income related to ineffectiveness for fair value hedges.

3 The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to energy revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles. In 2013 and 2012, there were no gains or losses included in net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of the Consolidated statement of OCI related to derivatives in cash flow hedging relationships is as follows:

year ended December 31 (millions of $, pre-tax)	**2013**	**2012**
Change in fair value of derivative instruments recognized in OCI (effective portion)		
Power	**117**	83
Natural Gas	**(1)**	(21)
Foreign Exchange	**5**	(1)
	121	61
Reclassification of gains on derivative instruments from AOCI to net income (effective portion)		
Power	**40**	147
Natural Gas	**4**	54
Interest	**16**	18
	60	219
Gains on derivative instruments recognized in earnings (ineffective portion)		
Power	**8**	7
	8	7

Credit risk related contingent features of derivative instruments

Derivatives often contain financial assurance provisions that may require us to provide collateral if a credit risk-related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2013, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $16 million (2012 $37 million), with collateral provided in the normal course of business of nil (2012 nil).

If the credit-risk-related contingent features in these agreements were triggered on December 31, 2013, we would have been required to provide additional collateral of $16 million (2012 $37 million) to our counterparties. We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

ACCOUNTING CHANGES

Changes in accounting policies for 2013

Balance sheet offsetting/netting

Effective January 1, 2013, we adopted the Accounting Standards Update (ASU) on disclosures about balance sheet offsetting as issued by the Financial Accounting Standards Board (FASB) to enable readers to evaluate the effects of netting arrangements on our financial position. Adoption of the ASU has resulted in increased qualitative and quantitative disclosures about certain derivative instruments that are either offset in accordance with current GAAP or are subject to a master netting arrangement or similar agreement.

Accumulated other comprehensive income

Effective January 1, 2013, we adopted the ASU on reporting of amounts reclassified out of accumulated other comprehensive income (AOCI) as issued by the FASB. Adoption of the ASU has resulted in providing additional qualitative and quantitative disclosures about significant amounts reclassified out of AOCI into net income.

Future accounting changes

Obligations resulting from joint and several liability arrangements

In February 2013, the FASB issued guidance for recognizing, measuring, and disclosing obligations resulting from joint and several liability arrangements when the total amount of the obligation is fixed at the reporting date. Debt arrangements, other contractual obligations, and settled litigation and judicial rulings are examples of these obligations. This ASU is effective retrospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2013. We are evaluating the impact that adopting the ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

Foreign currency matters cumulative translation adjustment

In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This ASU is effective prospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2013. Early adoption is allowed as of the beginning of the entity's fiscal year. We are evaluating the impact that adopting this ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

Unrecognized tax benefit

In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This ASU is effective prospectively for fiscal years and interim reporting periods within those years, beginning after December 15, 2014. Early adoption is permitted. We are evaluating the impact that adopting the ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(unaudited, millions of $, except per share amounts)

2013	Fourth	Third	Second	First
Revenues	**2,332**	**2,204**	**2,009**	**2,252**
Net income attributable to common shares	**420**	**481**	**365**	**446**
Comparable earnings	**410**	**447**	**357**	**370**
Comparable earnings per share	**$0.58**	**$0.63**	**$0.51**	**$0.52**
Share statistics				
Net income per share basic and diluted	**$0.59**	**$0.68**	**$0.52**	**$0.63**
Dividends declared per common share	**$0.46**	**$0.46**	**$0.46**	**$0.46**

2012	Fourth	Third	Second	First
Revenues	2,089	2,126	1,847	1,945
Net income attributable to common shares	306	369	272	352
Comparable earnings	318	349	300	363
Comparable earnings per share	$0.45	$0.50	$0.43	$0.52
Share statistics				
Net income per share basic and diluted	$0.43	$0.52	$0.39	$0.50
Dividends declared per common share	$0.44	$0.44	$0.44	$0.44

Factors affecting quarterly financial information by business segment

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In Natural Gas Pipelines, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' decisions
- negotiated settlements with shippers
- acquisitions and divestitures
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

In Oil Pipelines, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable.

In Energy, quarter-over-quarter revenues and net income are affected by:

- weather
- customer demand
- market prices for natural gas and energy
- capacity prices and payments
- planned and unplanned plant outages
- acquisitions and divestitures
- certain fair value adjustments
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

Factors affecting financial information by quarter

We calculate comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

Comparable earnings exclude the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

In second quarter 2013, comparable earnings excluded a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax in June 2013.

In first quarter 2013, comparable earnings excluded $84 million of net income in 2013 related to 2012 from the NEB decision.

In second quarter 2012, comparable earnings excluded a $15 million after tax charge ($20 million pre-tax) from the Sundance A PPA arbitration decision.

FOURTH QUARTER 2013 HIGHLIGHTS

Reconciliation of non-GAAP measures

three months ended December 31 (unaudited) (millions of $, except per share amounts)	**2013**	**2012**
EBITDA	**1,320**	1,040
Non-comparable risk management activities affecting EBITDA	**(29)**	12
Comparable EBITDA	**1,291**	1,052
Comparable depreciation and amortization	**(396)**	(343)
Comparable EBIT	**895**	709
Other income statement items		
Comparable interest expense	**(240)**	(246)
Comparable interest income and other	**10**	20
Comparable income tax	**(198)**	(123)
Net income attributable to non-controlling interests	**(38)**	(28)
Preferred share dividends	**(19)**	(14)
Comparable earnings	**410**	318
Specific item (net of tax):		
Risk management activities[1]	**10**	(12)
Net income attributable to common shares	**420**	306
Comparable interest expense	**(240)**	(246)
Specific item:		
Risk management activities[1]	**-**	-
Interest expense	**(240)**	(246)
Comparable interest income and other	**10**	20
Specific item:		
Risk management activities[1]	**(9)**	(5)
Interest income and other	**1**	15
Comparable income tax expense	**(198)**	(123)
Specific item:		
Risk management activities[1]	**(10)**	5
Income tax expense	**(208)**	(118)
Comparable earnings per common share	**$0.58**	$0.45
Specific item (net of tax):		
Risk management activities[1]	**0.01**	(0.02)
Net income per common share	**$0.59**	$0.43

1

three months ended December 31 (unaudited) (millions of $)	**2013**	2012
Risk management activities gains/(losses):		
Canadian Power	**(2)**	(6)
U.S. Power	**36**	(5)
Natural Gas Storage	**(5)**	(1)
Foreign exchange	**(9)**	(5)
Income tax attributable to risk management activities	**(10)**	5
Total gains/(losses) from risk management activities	**10**	(12)

Comparable EBITDA and comparable EBIT by Business Segment

three months ended December 31, 2013 (unaudited) (millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	**778**	**198**	**346**	**(31)**	**1,291**
Comparable depreciation and amortization	**(280)**	**(38)**	**(74)**	**(4)**	**(396)**
Comparable EBIT	**498**	**160**	**272**	**(35)**	**895**

three months ended December 31, 2012 (unaudited) (millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	690	172	222	(32)	1,052
Comparable depreciation and amortization	(236)	(36)	(68)	(3)	(343)
Comparable EBIT	454	136	154	(35)	709

Comparable earnings

Comparable earnings in fourth quarter 2013 were $92 million or $0.13 per share higher compared to the same period in 2012.

The increase in comparable earnings was primarily the result of:

- higher equity income from Bruce Power reflecting incremental earnings from Unit 4 due to fewer planned outage days and return to service of Units 1 and 2
- higher earnings from the Canadian Mainline due to the higher ROE of 11.50 per cent in 2013 compared to 8.08 per cent in 2012 due to the NEB decision
- higher earnings from the NGTL System because of a higher average investment base associated with 2012 and 2013 capital expenditures and the impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013 which included a higher ROE and incentive earnings
- higher earnings from the Keystone Pipeline System primarily due to higher volumes.

These increases were partly offset by:

- lower contribution from U.S. natural gas pipelines due to lower transportation revenue at ANR as well as reduced earnings from GTN and Bison due to the reduction of our effective ownership from 83 per cent to 50 per cent, beginning in July 2013
- lower earnings from Western Power primarily due to lower realized power prices.

Net income attributable to common shares

Our net income attributable to common shares was $420 million or $0.59 per share in fourth quarter 2013 compared to $306 million or $0.43 per share for the same period in 2012.

Highlights by business segment

Natural Gas Pipelines

Natural Gas Pipelines comparable EBIT increased $44 million for the three months ended December 31, 2013 compared to the same period in 2012 because of higher earnings from the Canadian Mainline due to the NEB decision in March 2013 and higher earnings from the NGTL System because of a higher average investment base associated with 2013 capital expenditures and the impact of the 2013-2014 NGTL Settlement which included a higher ROE of 10.10 per cent on 40 per cent deemed common equity. These increases were partially offset by lower contributions from GTN and Bison due to reduced effective ownership and lower revenue and higher OM&A costs at ANR.

Natural Gas Pipelines comparable depreciation and amortization increased by $44 million for the three months ended December 31, 2013 compared to the same period in 2012 mainly due to a 2013 true-up for the higher composite depreciation rate in the 2013-2014 NGTL Settlement approved in November 2013, a higher investment base on the NGTL System, and the impact of the NEB decision on the Canadian Mainline.

Canadian Pipelines

Canadian Mainline's comparable earnings increased by $29 million for the three months ended December 31, 2013 compared to the same period in 2012 because of the impact of the NEB decision in March 2013 and higher incentive earnings. Among other items, the NEB approved an ROE of 11.50 per cent on 40 per cent deemed common equity for the years 2012 through to 2017 compared to the last approved ROE of 8.08 per cent on deemed common equity of 40 per cent that was used to record earnings in 2012 as well as an incentive mechanism based on total net revenues. The increase in comparable earnings relates almost fully to the higher ROE and some incentive earnings.

Net income for the NGTL System increased by $17 million for the three months ended December 31, 2013 compared to the same period in 2012 because of the impact of the 2013-2014 NGTL Settlement which included a higher ROE and incentive earnings and a higher average investment base associated with 2012 and 2013 capital expenditures. The settlement, approved by the NEB in November 2013, included an ROE of 10.10 per cent on 40 per cent deemed common equity compared to an ROE of 9.70 per cent on 40 per cent deemed common equity in 2012. The settlement also included annual fixed amounts for certain OM&A costs.

U.S. Pipelines

Comparable EBITDA for the U.S. and international pipelines decreased by US$30 million for the three months ended December 31, 2013 compared to the same period in 2012. This was the net effect of:

- lower transportation and storage revenues at ANR
- higher OM&A and costs relating to services provided by other pipelines at ANR
- lower contributions from GTN and Bison as a result of a reduction of our effective ownership in each pipeline from 83 per cent in 2012 to 50 per cent effective July 1, 2013
- higher contributions from Portland due to higher short term revenues.

Oil Pipelines

Comparable EBITDA for Oil Pipelines increased by $26 million primarily due to the Keystone Pipeline System which increased by $20 million for the three months ended December 31, 2013 compared to the same period in 2012. These increases reflected higher revenues primarily resulting from higher volumes.

Energy

Comparable EBITDA for Energy increased by $124 million for the three months ended December 31, 2013 compared to the same period in 2012. The increase was the effect of:

- higher equity income from Bruce Power mainly because of incremental earnings from Unit 4 due to fewer planned outage days and the return to service of Units 1 and 2
- higher earnings from U.S. Power mainly because of higher capacity prices in New York offset by lower volumes, primarily at the Ravenswood facility
- lower earnings from Western Power mainly because of lower realized power prices partly offset by the return to service of the Sundance A PPA Unit 1 in early September 2013 and Unit 2 in early October 2013.

Western Power's comparable EBITDA decreased by $24 million for the three months ended December 31, 2013 compared to the same period in 2012 due to the net effect of:

- lower realized power prices
- incremental earnings from the return to service of the Sundance A Unit 1 in early September 2013 and Unit 2 in early October 2013.

Average spot market power prices in Alberta decreased by 39 per cent to $48/MWh for the three months ended December 31, 2013 compared to the same period in 2012. This decrease was the result of changes in the Alberta power supply and demand balance reflecting the return of Sundance A Units 1 and 2, significantly fewer coal plant outages and higher wind output in fourth quarter 2013 compared to fourth quarter 2012.

Realized power prices on power sales can be higher or lower than spot market power prices in any given period, as a result of contracting activities.

Purchased volumes for the three months ended December 31, 2013 were higher compared to the same period in 2012 mainly because of the return to service of Sundance A Units 1 and 2.

Approximately 68 per cent of Western Power sales volumes were sold under contract this quarter compared to 80 per cent in fourth quarter 2012. To reduce exposure to spot market prices in Alberta, Western Power enters into fixed price forward sales to secure future revenue and a portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. The amount sold forward will vary depending on market conditions and market liquidity and has historically ranged between 25 to 75 per cent of expected future production with a higher proportion being hedged in the near term periods. Such forward sales may be completed with medium and large industrial and commercial companies and other market participants and will affect our average realized price (versus spot price) in future periods.

Equity income from Bruce A increased by $124 million for the three months ended December 31, 2013 compared to the same period in 2012. The increase was mainly due to:

- incremental earnings from Unit 4 due to the planned life extension outage which began in third quarter 2012 and was completed in April 2013
- incremental earnings from Units 1 and 2 which returned to service in October 2012
- higher realized prices.

U.S. Power's comparable EBITDA increased by US$17 million for the three months ended December 31, 2013 compared to the same period in 2012. The increase was the net effect of:

- higher realized capacity prices in New York
- higher realized power prices in New England offset by the impact of higher fuel costs
- lower generation, primarily at the Ravenswood facility.

Natural Gas Storage's comparable EBITDA increased by $7 million for the three months ended December 31, 2013 compared to the same period in 2012 mainly due to higher volumes at higher realized natural gas storage spreads and incremental earnings from CrossAlta resulting from the acquisition of the remaining 40 per cent interest in December 2012.

Glossary

Units of measure

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

General terms and terms related to our operations

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

Accounting terms

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

Government and regulatory bodies terms

CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
DOS	Department of State (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IEA	International Energy Agency
ISO	Independent System Operator

LMCI	Land Matters Consultation Initiative (Canada)
NEB	National Energy Board (Canada)
OPA	Ontario Power Authority (Canada)
RGGI	Regional Greenhouse Gas Initiative (northeastern U.S.)
SEC	U.S. Securities and Exchange Commission

Report of management

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada Corporation (TransCanada or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgements. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2013 to that in 2012, and highlights significant changes between 2012 and 2011. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control Integrated Framework 1992 issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2013, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examinations and its opinions on the consolidated financial statements and the effectiveness of the Company's internal control over financial reporting.

Russell K. Girling	**Donald R. Marchand**
President and	Executive Vice-President and
Chief Executive Officer	Chief Financial Officer

February 19, 2014

Independent Auditors' Report of Registered Public Accounting Firm

TO THE SHAREHOLDERS OF TRANSCANADA CORPORATION

We have audited the accompanying consolidated financial statements of TransCanada Corporation, which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012, the consolidated statements of income, comprehensive income, equity and cash flows for each of the years in the three-year period ended December 31, 2013, and notes, comprising a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITORS' RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransCanada Corporation as at December 31, 2013 and December 31, 2012, and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2013 in accordance with U.S. generally accepted accounting principles.

OTHER MATTER

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransCanada Corporation's internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control   Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 19, 2014 expressed an unmodified (unqualified) opinion on the effectiveness of TransCanada Corporation's internal control over financial reporting.

Chartered Accountants
Calgary, Canada
February 19, 2014

Report of Independent Registered Public Accounting Firm

TO THE SHAREHOLDERS OF TRANSCANADA CORPORATION

We have audited TransCanada Corporation's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control   Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). TransCanada Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, TransCanada Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control   Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TransCanada Corporation as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, equity and cash flows for each of the years in the three-year period ended December 31, 2013, and our report dated February 19, 2014 expressed an unmodified (unqualified) opinion on those consolidated financial statements.

Chartered Accountants
Calgary, Canada

February 19, 2014

Consolidated statement of income

year ended December 31 (millions of Canadian dollars except per share amounts)	**2013**	**2012**	**2011**
Revenues			
Natural Gas Pipelines	**4,497**	4,264	4,244
Oil Pipelines	**1,124**	1,039	827
Energy	**3,176**	2,704	2,768
	8,797	8,007	7,839
Income from Equity Investments (Note 8)	**597**	257	415
Operating and Other Expenses			
Plant operating costs and other	**2,674**	2,577	2,358
Commodity purchases resold	**1,317**	1,049	991
Property taxes	**445**	434	410
Depreciation and amortization	**1,485**	1,375	1,328
	5,921	5,435	5,087
Financial Charges/(Income)			
Interest expense (Note 15)	**985**	976	937
Interest income and other	**(34)**	(85)	(55)
	951	891	882
Income before Income Taxes	**2,522**	1,938	2,285
Income Tax Expense (Note 16)			
Current	**43**	181	210
Deferred	**568**	285	365
	611	466	575
Net Income	**1,911**	1,472	1,710
Net Income Attributable to Non-Controlling Interests (Note 18)	**125**	118	129
Net Income Attributable to Controlling Interests	**1,786**	1,354	1,581
Preferred Share Dividends (Note 20)	**74**	55	55
Net Income Attributable to Common Shares	**1,712**	1,299	1,526
Net Income per Common Share (Note 19)			
Basic and Diluted	**$2.42**	$1.84	$2.17
Dividends Declared per Common Share	**$1.84**	$1.76	$1.68

Weighted Average Number of Common Shares (millions)			
Basic	**707**	705	702
Diluted	**708**	706	703

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian dollars)	**2013**	**2012**	**2011**
Net Income	**1,911**	1,472	1,710
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investments in foreign operations	**383**	(129)	137
Change in fair value of net investment hedges	**(239)**	44	(73)
Change in fair value of cash flow hedges	**71**	48	(212)
Reclassification to Net Income of gains and losses on cash flow hedges	**41**	138	147
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**67**	(73)	(89)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**23**	22	10
Other Comprehensive Income/(Loss) on equity investments	**234**	(70)	(91)
Other Comprehensive Income/(Loss) (Note 21)	**580**	(20)	(171)
Comprehensive Income	**2,491**	1,452	1,539
Comprehensive Income Attributable to Non-Controlling Interests	**191**	97	164
Comprehensive Income Attributable to Controlling Interests	**2,300**	1,355	1,375
Preferred Share Dividends	**74**	55	55
Comprehensive Income Attributable to Common Shares	**2,226**	1,300	1,320

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of cash flows

year ended December 31 (millions of Canadian dollars)	**2013**	**2012**	**2011**
Cash Generated from Operations			
Net income	**1,911**	1,472	1,710
Depreciation and amortization	**1,485**	1,375	1,328
Deferred income taxes (Note 16)	**568**	285	365
Income from equity investments (Note 8)	**(597)**	(257)	(415)
Distributed earnings received from equity investments (Note 8)	**605**	376	393
Employee post-retirement benefits funding lower than/(in excess of) expense (Note 22)	**50**	9	(2)
Other	**(22)**	24	72
(Increase)/decrease in operating working capital (Note 24)	**(326)**	287	235
Net cash provided by operations	**3,674**	3,571	3,686
Investing Activities			
Capital expenditures (Note 4)	**(4,461)**	(2,595)	(2,513)
Equity investments	**(163)**	(652)	(633)
Acquisitions, net of cash acquired (Note 25)	**(216)**	(214)	
Deferred amounts and other	**(280)**	205	92
Net cash used in investing activities	**(5,120)**	(3,256)	(3,054)
Financing Activities			
Dividends on common and preferred shares (Notes 19 and 20)	**(1,356)**	(1,281)	(1,016)
Distributions paid to non-controlling interests	**(166)**	(135)	(131)
Notes payable (repaid)/issued, net	**(492)**	449	(224)
Long-term debt issued, net of issue costs	**4,253**	1,491	1,622
Repayment of long-term debt	**(1,286)**	(980)	(1,272)
Common shares issued	**72**	53	58
Preferred shares issued, net of issue costs	**585**		
Partnership units of subsidiary issued, net of issue costs (Note 25)	**384**		321
Preferred shares of subsidiary redeemed (Note 18)	**(200)**		
Net cash provided by/(used in) financing activities	**1,794**	(403)	(642)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**28**	(15)	4
Increase/(Decrease) in Cash and Cash Equivalents	**376**	(103)	(6)
Cash and Cash Equivalents			
Beginning of year	**551**	654	660
Cash and Cash Equivalents			
End of year	**927**	551	654

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian dollars)	2013	2012
ASSETS		
Current Assets		
Cash and cash equivalents	**927**	551
Accounts receivable	**1,122**	1,052
Inventories	**251**	224
Other (Note 5)	**847**	997
	3,147	2,824
Plant, Property and Equipment (Note 7)	**37,606**	33,713
Equity Investments (Note 8)	**5,759**	5,366
Regulatory Assets (Note 9)	**1,735**	1,629
Goodwill (Note 10)	**3,696**	3,458
Intangible and Other Assets (Note 11)	**1,955**	1,406
	53,898	48,396
LIABILITIES		
Current Liabilities		
Notes payable (Note 12)	**1,842**	2,275
Accounts payable and other (Note 13)	**2,155**	2,344
Accrued interest	**388**	368
Current portion of long-term debt (Note 15)	**973**	894
	5,358	5,881
Regulatory Liabilities (Note 9)	**229**	268
Other Long-Term Liabilities (Note 14)	**656**	882
Deferred Income Tax Liabilities (Note 16)	**4,564**	4,016
Long-Term Debt (Note 15)	**21,892**	18,019
Junior Subordinated Notes (Note 17)	**1,063**	994
	33,762	30,060
EQUITY		
Common shares, no par value (Note 19)	**12,149**	12,069
Issued and outstanding: December 31, 2013 707 million shares		
December 31, 2012 705 million shares		
Preferred shares (Note 20)	**1,813**	1,224
Additional paid-in capital	**401**	379
Retained earnings	**5,096**	4,687
Accumulated other comprehensive loss (Note 21)	**(934)**	(1,448)
Controlling interests	**18,525**	16,911
Non-controlling interests (Note 18)	**1,611**	1,425
	20,136	18,336
	53,898	48,396

Commitments, Contingencies and Guarantees (Note 26)

Subsequent Events (Note 27)

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

Russell K. Girling Director	**Kevin E. Benson** Director

Consolidated statement of equity

year ended December 31 (millions of Canadian dollars)	2013	2012	2011
Common Shares			
Balance at beginning of year	**12,069**	12,011	11,745
Shares issued under dividend reinvestment plan (Note 19)			202
Shares issued on exercise of stock options (Note 19)	**80**	58	64
Balance at end of year	**12,149**	12,069	12,011
Preferred Shares			
Balance at beginning of year	**1,224**	1,224	1,224
Shares issued under public offering, net of issue costs	**589**		
Balance at end of year	**1,813**	1,224	1,224
Additional Paid-In Capital			
Balance at beginning of year	**379**	380	349
Issuance of stock options, net of exercises	**(2)**	(1)	1
Dilution impact from TC PipeLines, LP units issued (Note 25)	**29**		30
Redemption of subsidiary's preferred shares	**(5)**		
Balance at end of year	**401**	379	380
Retained Earnings			
Balance at beginning of year	**4,687**	4,628	4,282
Net income attributable to controlling interests	**1,786**	1,354	1,581
Common share dividends	**(1,301)**	(1,240)	(1,180)
Preferred share dividends	**(76)**	(55)	(55)
Balance at end of year	**5,096**	4,687	4,628
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(1,448)**	(1,449)	(1,243)
Other comprehensive income/(loss)	**514**	1	(206)
Balance at end of year	**(934)**	(1,448)	(1,449)
Equity Attributable to Controlling Interests	**18,525**	16,911	16,794
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,425**	1,465	1,157
Net income attributable to non-controlling interests			
TC PipeLines, LP	**93**	91	101
Preferred share dividends of TCPL	**20**	22	22
Portland	**12**	5	6
	66	(21)	35

Other comprehensive income/(loss) attributable to non-controlling interests			
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**384**		321
Decrease in TransCanada's ownership of TC PipeLines, LP	**(47)**		(50)
Distributions declared to non-controlling interests	**(166)**	(135)	(131)
Redemption of subsidiary's preferred shares	**(195)**		
Foreign exchange and other	**19**	(2)	4
Balance at end of year	**1,611**	1,425	1,465
Total Equity	**20,136**	18,336	18,259

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada or the Company) is a leading North American energy company which operates in three business segments, Natural Gas Pipelines, Oil Pipelines and Energy, each of which offers different products and services.

Natural Gas Pipelines

The Natural Gas Pipelines segment consists of the Company's investments in regulated natural gas pipelines and regulated natural gas storage facilities. Through its Natural Gas Pipelines segment, TransCanada owns and operates:

- a natural gas transmission system extending from the Alberta/Saskatchewan border, east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta and northeastern B.C. (NGTL System);
- a natural gas transmission system extending from producing fields primarily located in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets primarily located in Wisconsin, Michigan, Illinois, Ohio and Indiana, and includes regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from central Alberta to the B.C./Idaho border and to the Saskatchewan/Montana border (Foothills);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP);
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale); and
- a natural gas transmission system in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco (Guadalajara).

Through its Natural Gas Pipelines segment, TransCanada operates and has ownership interests in natural gas pipeline systems as follows:

- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in eastern Canada and the northeastern and midwestern U.S. (Great Lakes);
- a 30 per cent direct ownership interest in a natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border (GTN);
- a 30 per cent direct ownership interest in a natural gas transmission system extending from the Powder River Basin in Wyoming to Northern Border in North Dakota (Bison);
- a 61.7 per cent interest in a natural gas transmission system that extends from a point near East Hereford, Québec, to the northeastern U.S. (Portland);
- a 50 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec and to the Portland system (TQM); and
- a 28.9 per cent controlling interest in TC PipeLines, LP, which has the following ownership interests in pipelines operated by TransCanada:
  - a 46.4 per cent interest in Great Lakes, in which TransCanada has a combined 67 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;

a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TransCanada has a 14.5 per cent effective ownership interest through TC PipeLines, LP;

a 70 per cent interest in GTN, in which TransCanada has a combined 50.2 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;

- a 70 per cent interest in Bison, in which TransCanada has a combined 50.2 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;
- a 100 per cent interest in a natural gas transmission system extending from Arizona to Baja California at the Mexico/California border (North Baja), in which TransCanada has a 28.9 per cent effective ownership interest through TC PipeLines, LP; and
- a 100 per cent interest in a natural gas transmission system extending from Malin, Oregon, to Wadsworth, Nevada (Tuscarora), in which TransCanada has a 28.9 per cent effective ownership interest through TC PipeLines, LP.

TransCanada has a 44.5 per cent ownership interest in a natural gas pipeline transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S. (Iroquois). TransCanada does not operate this pipeline.

TransCanada is currently constructing natural gas pipeline systems in Mexico as follows:

- an extension to the Tamazunchale pipeline from Tamazunchale, San Luis Potosi to El Sauz, Queretaro;
- a natural gas transmission system that will transport natural gas from El Encino, Chihuahua to Topolobampo, Sinaloa (Topolobampo); and
- a natural gas transmission system that will transport natural gas from El Oro to Mazatlan, Sinaloa (Mazatlan).

TransCanada is currently developing the following natural gas pipeline systems:

- the proposed Coastal GasLink project consisting of a natural gas transmission system that will transport natural gas from the Montney gas-producing region near Dawson Creek, B.C. to a liquefied natural gas (LNG) export facility near Kitimat, B.C.; and
- the proposed Prince Rupert Gas Transmission project consisting of a pipeline to deliver natural gas from the Fort St. John area of B.C. to the proposed Pacific Northwest LNG facility at Port Edward near Prince Rupert, B.C.

Oil Pipelines

The Oil Pipelines segment consists of a wholly owned and operated crude oil pipeline system which connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas (Keystone Pipeline System).

TransCanada is currently constructing oil pipeline infrastructure as follows:

- a crude oil pipeline to connect the crude oil hub at Cushing, Oklahoma to the U.S. Gulf Coast refining market (Gulf Coast project);
- the Cushing Marketlink receipt facilities that will transport crude oil supply from the market hub at Cushing, Oklahoma to the U.S. Gulf Coast on facilities that form part of the Keystone Pipeline System; and
- a crude oil terminal to be located at Hardisty, Alberta (Keystone Hardisty Terminal) that will provide Western Canadian producers with new batch accumulation tankage and pipeline infrastructure and access to the Keystone Pipeline System.

TransCanada is currently developing oil pipeline infrastructure as follows:

- a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska (Keystone XL), subject to regulatory approval;
- the Bakken Marketlink project that will transport crude oil supply from the Williston Basin in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL;

the Energy East Pipeline that will transport crude oil from western Canada to eastern refineries and export terminals. This project will include conversion of certain Canadian Mainline natural gas assets to crude oil service;

the Heartland Pipeline and TC Terminals projects that will include a crude oil pipeline connecting the Edmonton and Hardisty, Alberta market regions and a terminal facility in the Heartland industrial area north of Edmonton;

the Northern Courier Pipeline, a pipeline that will transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal facilities located north of Fort McMurray, Alberta; and

the Grand Rapids Pipeline in northern Alberta, which includes both crude oil and diluent lines to transport volumes between the producing area northwest of Fort McMurray and the Edmonton/Heartland region. The Company has entered into a joint venture agreement with a third party to develop the pipeline.

Energy

The Energy segment primarily consists of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company owns and operates:

a natural gas and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);

a natural gas-fired, combined-cycle power plant in Halton Hills, Ontario (Halton Hills);

hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);

a natural gas-fired peaking facility located near Phoenix, Arizona (Coolidge);

a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);

a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);

natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;

a wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine (Kibby Wind);

a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview);

a waste-heat fueled power plant and the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);

a natural gas storage facility near Edson, Alberta (Edson);

an underground natural gas storage facility near Crossfield, Alberta (CrossAlta); and

four solar facilities in Ontario (Ontario Solar).

TransCanada does not operate but has ownership interests in power generation plants as follows:

a 48.9 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce A and Bruce B (collectively Bruce Power), respectively, located near Tiverton, Ontario;

a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau, Carleton, Montagne-Sèche and Gros-Morne wind farms in Gaspé, Québec (Cartier Wind); and

a 50 per cent interest in a natural gas-fired, combined-cycle plant in Toronto, Ontario (Portlands Energy).

TransCanada has long-term power purchase arrangements (PPA) in place for:

a 100 per cent interest in the Sheerness power facility near Hanna, Alberta;

a 100 per cent interest in the Sundance A power facilities near Wabamun, Alberta.

In addition, TransCanada has a 50 per cent interest in the ASTC Power Partnership which holds a PPA for a 100 per cent interest in the Sundance B power facilities near Wabamun, Alberta.

TransCanada is currently constructing a natural gas-fired power plant at Ontario Power Generation's Lennox site in Greater Napanee, Ontario (Napanee).

TransCanada also has agreed to purchase an additional five Ontario solar facilities in 2014.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

The consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TransCanada uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TransCanada records its proportionate share of undivided interests in certain assets. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgements

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies summarized below.

Regulation

In Canada, regulated natural gas pipelines and oil pipelines are subject to the authority of the National Energy Board (NEB) of Canada. In the U.S., natural gas pipelines, oil pipelines and regulated natural gas storage assets are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). In Mexico, natural gas pipelines are subject to the authority of the Energy Regulatory Commission of Mexico. The Company's Canadian and U.S. natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TransCanada's rate-regulated businesses which may differ from that otherwise expected in non-rate-regulated businesses to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. TransCanada's businesses that apply RRA currently include Canadian and U.S. natural gas pipelines and regulated U.S. natural gas storage. RRA is not applicable to the Keystone Pipeline System and the Company's Mexican natural gas pipelines and, as a result, the regulators' decisions regarding operations and tolls on these pipelines generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Natural Gas and Oil Pipelines

Revenues from the Company's natural gas and oil pipelines, with the exception of Canadian natural gas pipelines which are subject to rate regulation, are generated from contractual arrangements for committed capacity and from the transportation of natural gas or crude oil. Revenues earned from firm contracted capacity arrangements are recognized ratably over the contract period regardless of the amount of natural gas or crude oil that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when physical deliveries of natural gas or crude oil are made. The U.S. natural gas pipelines are subject to FERC regulations and, as a result, revenues collected may be subject to refund during a rate proceeding. Allowances for these potential refunds are recognized at the time of the regulatory decision.

Revenues from Canadian natural gas pipelines subject to rate regulation are recognized in accordance with decisions made by the NEB. The Company's Canadian natural gas pipeline rates are based on revenue requirements designed to recover the costs of providing natural gas transportation services, which include an appropriate return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines are not subject to risks related to variances in revenues and most costs. These variances are generally subject to deferral treatment and are recovered or refunded in future rates. The Company's Canadian natural gas pipelines are periodically subject to incentive mechanisms, as negotiated with shippers and approved by the NEB. These mechanisms can result in the Company recognizing more or less revenue than required to recover the costs that are subject to incentives. Revenues are recognized on firm contracted capacity ratably over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made. Revenues recognized prior to an NEB decision on rates for that period reflect the NEB's last approved rate of return on common equity (ROE) assumptions. Adjustments to revenue are recorded when the NEB decision is received.

Revenues from the Company's regulated natural gas storage services are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored and when gas is injected or withdrawn for interruptible or volumetric-based services. The Company does not take ownership of the gas or oil that it transports or stores for others.

Energy

Power

Revenues from the Company's Energy business are primarily derived from the sale of electricity and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, as well as gains and losses resulting from the use of commodity derivative contracts. The accounting for derivative contracts is described in the Derivative Instruments and Hedging Activities section of this note.

Natural Gas Storage

Revenues earned from providing non-regulated natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Derivative contracts for the purchase or sale of natural gas are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's Cash and Cash Equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies, including spare parts and fuel, and natural gas inventory in storage, and are carried at the lower of weighted average cost or market.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to six per cent, and metering and other plant equipment are depreciated at various rates. The cost of overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in plant, property and equipment and the equity component of AFUDC is a non-cash expenditure. Interest is capitalized during construction of non-regulated natural gas pipelines.

When regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Oil Pipelines

Plant, property and equipment for oil pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. The cost of these assets includes interest capitalized during construction. When oil pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Energy

Power generation and natural gas storage plant, equipment and structures are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates. The cost of overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Corporate

Corporate plant, property and equipment are recorded at cost and depreciated on a straight-line basis over their estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Impairment of Long-Lived Assets

The Company reviews long-lived assets, such as plant, property and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that the asset might be impaired. The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company initially assesses qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired. If TransCanada concludes that it is not more likely than not that fair value of the reporting unit is greater than its carrying value, the first step of the two-step impairment test is performed by comparing the fair value of the reporting unit to its book value, which includes goodwill. If the fair value is less than book value, an impairment is indicated and a second step is performed to measure the amount of the impairment. In the second step, the implied fair value of goodwill is calculated by deducting the recognized amounts of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded in an amount equal to the difference.

Power Purchase Arrangements

A PPA is a long-term contract for the purchase or sale of power on a predetermined basis. The PPAs under which TransCanada buys power are accounted for as operating leases. The initial payments for these PPAs were recognized in Intangible and Other Assets and amortized on a straight-line basis over the term of the contracts, which expire in 2017 and 2020. A portion of these PPAs has been subleased to third parties under terms and conditions similar to the PPAs. The subleases are accounted for as operating leases and TransCanada records the margin earned from the subleases as a component of Revenues.

Income Taxes

The Company uses the liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, NGTL System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to operating expenses.

Recorded ARO relates to the non-regulated natural gas storage operations and certain power generation facilities. The scope and timing of asset retirements related to natural gas pipelines, oil pipelines and hydroelectric power plants is indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Balance Sheet at historical cost and expensed when they are utilized. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TransCanada are not attributed a value for accounting purposes. When required, TransCanada accrues emission liabilities on the Balance Sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues.

Stock Options and Other Compensation Programs

TransCanada's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period, with an offset to Additional Paid-In Capital. Upon exercise of stock options, amounts originally recorded against Additional Paid-In Capital are reclassified to Common Shares.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a savings plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and savings plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Balance Sheet and recognizes changes in that funded status through Other Comprehensive Income (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated Other Comprehensive Loss (AOCI) over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the average remaining service life of active employees.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the company or reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in income except for exchange gains and losses of the foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. The Company's U.S. dollar-denominated debt has been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar denominated debt are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify and are designated for hedge accounting treatment, which includes fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in Net Income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest Income and Other and Interest Expense, respectively. If hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net Income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net Income in the same financial statement category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net Income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net Income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In hedging the foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net Income. The amounts recognized previously in AOCI are reclassified to Net Income in the event the Company reduces its net investment in a foreign operation.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in Net Income in the period of change.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as Regulatory Assets or Regulatory Liabilities and are refunded to or collected from the ratepayers, in subsequent years when the derivative settles.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are measured separately, they are included in Net Income.

Long-Term Debt Transaction Costs

The Company records Long-Term Debt transaction costs as other assets and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company or partially owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to Equity Investments, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Other Long-Term Liabilities.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2013

Balance Sheet Offsetting/Netting

Effective January 1, 2013, the Company adopted the Accounting Standards Update (ASU) on disclosures about balance sheet offsetting as issued by the Financial Accounting Standards Board (FASB) to enable readers to evaluate the effects of netting arrangements on the Company's financial position. Adoption of the ASU has resulted in increased qualitative and quantitative disclosures regarding certain derivative instruments that are either offset in accordance with current GAAP or are subject to a master netting arrangement or similar agreement. These disclosures have been included in Note 23, Risk Management and Financial Instruments.

Accumulated Other Comprehensive Income

Effective January 1, 2013, the Company adopted the ASU on reporting of amounts reclassified out of AOCI as issued by the FASB. Adoption of the ASU has resulted in providing additional qualitative and quantitative disclosures regarding significant amounts reclassified out of AOCI into net income. These disclosures have been included in Note 21, Other Comprehensive Income and Accumulated Other Comprehensive Loss.

Future Accounting Changes

Obligations Resulting from Joint and Several Liability Arrangements

In February 2013, the FASB issued guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. Examples of obligations within the scope of this ASU include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. This ASU is effective retrospectively for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

Foreign Currency Matters   Cumulative Translation Adjustment

In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This ASU is effective prospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2013. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

Unrecognized Tax Benefit

In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This ASU is effective prospectively for fiscal years and interim reporting periods within those years, beginning after December 15, 2013. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

4. SEGMENTED INFORMATION

year ended December 31, 2013 (millions of Canadian dollars)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**4,497**	**1,124**	**3,176**		**8,797**
Income from Equity Investments	**145**		**452**		**597**
Plant Operating Costs and Other	**(1,405)**	**(328)**	**(833)**	**(108)**	**(2,674)**
Commodity Purchases Resold			**(1,317)**		**(1,317)**
Property Taxes	**(329)**	**(44)**	**(72)**		**(445)**
Depreciation and Amortization	**(1,027)**	**(149)**	**(293)**	**(16)**	**(1,485)**
	1,881	**603**	**1,113**	**(124)**	**3,473**
Interest Expense					**(985)**
Interest Income and Other					**34**
Income before Income Taxes					**2,522**
Income Tax Expense					**(611)**
Net Income					**1,911**
Net Income Attributable to Non-Controlling Interests					**(125)**
Net Income Attributable to Controlling Interests					**1,786**
Preferred Share Dividends					**(74)**
Net Income Attributable to Common Shares					**1,712**

year ended December 31, 2012 (millions of Canadian dollars)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,264	1,039	2,704		8,007
Income from Equity Investments	157		100		257
Plant Operating Costs and Other	(1,365)	(296)	(819)	(97)	(2,577)
Commodity Purchases Resold			(1,049)		(1,049)
Property Taxes	(315)	(45)	(74)		(434)
Depreciation and Amortization	(933)	(145)	(283)	(14)	(1,375)
	1,808	553	579	(111)	2,829
Interest Expense					(976)
Interest Income and Other					85
Income before Income Taxes					1,938
Income Tax Expense					(466)

Net Income	1,472
Net Income Attributable to Non-Controlling Interests	(118)
Net Income Attributable to Controlling Interests	1,354
Preferred Share Dividends	(55)
Net Income Attributable to Common Shares	1,299

year ended December 31, 2011 (millions of Canadian dollars)	**Natural Gas Pipelines**	**Oil Pipelines[1]**	**Energy**	**Corporate**	**Total**
Revenues	4,244	827	2,768		7,839
Income from Equity Investments	159		256		415
Plant Operating Costs and Other	(1,221)	(209)	(842)	(86)	(2,358)
Commodity Purchases Resold			(991)		(991)
Property Taxes	(307)	(31)	(72)		(410)
Depreciation and Amortization	(923)	(130)	(261)	(14)	(1,328)
	1,952	457	858	(100)	3,167
Interest Expense					(937)
Interest Income and Other					55
Income before Income Taxes					2,285
Income Tax Expense					(575)
Net Income					1,710
Net Income Attributable to Non-Controlling Interests					(129)
Net Income Attributable to Controlling Interests					1,581
Preferred Share Dividends					(55)
Net Income Attributable to Common Shares					1,526

1 Commencing in February 2011, TransCanada began recording earnings for the Keystone Pipeline System.

Total Assets

at December 31 (millions of Canadian dollars)	**2013**	**2012**
Natural Gas Pipelines	**25,165**	23,210
Oil Pipelines	**13,253**	10,485
Energy	**13,747**	13,157
Corporate	**1,733**	1,544
	53,898	48,396

Geographic Information

year ended December 31 (millions of Canadian dollars)	2013	2012	2011
Revenues			
Canada domestic	**4,659**	3,527	3,929
Canada export	**997**	1,121	1,087
United States	**3,029**	3,252	2,752
Mexico	**112**	107	71
	8,797	8,007	7,839

at December 31 (millions of Canadian dollars)	2013	2012
Plant, Property and Equipment		
Canada	**18,462**	18,054
United States	**17,570**	14,904
Mexico	**1,574**	755
	37,606	33,713

Capital Expenditures

year ended December 31 (millions of Canadian dollars)	2013	2012	2011
Natural Gas Pipelines	**1,776**	1,389	917
Oil Pipelines	**2,483**	1,145	1,204
Energy	**152**	24	384
Corporate	**50**	37	8
	4,461	2,595	2,513

5. OTHER CURRENT ASSETS

at December 31 (millions of Canadian dollars)	2013	2012
Fair value of derivative contracts (Note 23)	**395**	259
Deferred income tax assets (Note 16)	**119**	290
Assets held for sale (Note 6)	**85**	
Regulatory Assets (Note 9)	**42**	178
Other	**206**	270
	847	997

6. ASSETS HELD FOR SALE

at December 31 (millions of Canadian dollars)	2013
Assets Held for Sale	
Cash and Cash Equivalents	1
Accounts Receivable	12
Inventories	11
Plant, Property and Equipment	61
Total Assets Held for Sale (included in Other Current Assets, Note 5)	85
Liabilities Related to Assets Held for Sale	
Accounts Payable and Other	4
Other Long-Term Liabilities	1
Total Liabilities Related to Assets Held for Sale (included in Accounts Payable and Other, Note 13)	5

We classify assets as held for sale when management approves and commits to a formal plan to actively market an asset for sale and we expect the sale to close within the next twelve months. Upon classifying an asset as held for sale, we record the asset at the lower of its carrying amount or its estimated fair value, reduced for selling costs, and we stop recording depreciation expense on the asset.

At December 31, 2013, the Company classified Cancarb Limited and its related power generation facility as assets held for sale. The assets were recorded at their carrying amount at December 31, 2013. These assets and the related liabilities are recorded in the Energy Segment.

On January 20, 2014, the Company reached an agreement to sell these assets for aggregate gross proceeds of $190 million. Please refer to the Subsequent Events note (Note 27) for further details.

7. PLANT, PROPERTY AND EQUIPMENT

	2013			2012		
at December 31 (millions of Canadian dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Natural Gas Pipelines[1]						
Canadian Mainline						
Pipeline	**8,970**	**5,457**	**3,513**	8,801	5,192	3,609
Compression	**3,392**	**1,961**	**1,431**	3,370	1,880	1,490
Metering and other	**409**	**174**	**235**	391	182	209
	12,771	**7,592**	**5,179**	12,562	7,254	5,308
Under construction	**85**		**85**	163		163
	12,856	**7,592**	**5,264**	12,725	7,254	5,471
NGTL System						
Pipeline	**7,813**	**3,410**	**4,403**	7,214	3,221	3,993
Compression	**2,038**	**1,253**	**785**	1,885	1,177	708
Metering and other	**947**	**418**	**529**	958	420	538
	10,798	**5,081**	**5,717**	10,057	4,818	5,239
Under construction	**290**		**290**	463		463
	11,088	**5,081**	**6,007**	10,520	4,818	5,702
ANR						
Pipeline	**922**	**59**	**863**	864	49	815
Compression	**635**	**81**	**554**	514	72	442
Metering and other	**535**	**91**	**444**	520	81	439
	2,092	**231**	**1,861**	1,898	202	1,696
Under construction	**67**		**67**	63		63
	2,159	**231**	**1,928**	1,961	202	1,759
Other Natural Gas Pipelines						
GTN	**1,685**	**488**	**1,197**	1,565	411	1,154
Great Lakes	**1,650**	**833**	**817**	1,544	750	794
Foothills	**1,649**	**1,120**	**529**	1,634	1,062	572
Mexico	**641**	**90**	**551**	536	59	477
Other[2]	**1,652**	**288**	**1,364**	1,548	226	1,322
	7,277	**2,819**	**4,458**	6,827	2,508	4,319
Under construction	**1,047**		**1,047**	297		297
	8,324	**2,819**	**5,505**	7,124	2,508	4,616
	34,427	**15,723**	**18,704**	32,330	14,782	17,548

Oil Pipelines						
Keystone						
Pipeline	**5,079**	**286**	**4,793**	4,828	177	4,651
Pumping equipment	**1,118**	**82**	**1,036**	1,066	51	1,015
Tanks and other	**962**	**71**	**891**	935	47	888
	7,159	**439**	**6,720**	6,829	275	6,554
Under construction[3]	**6,020**		**6,020**	3,678		3,678
	13,179	**439**	**12,740**	10,507	275	10,232
Energy						
Natural Gas Ravenswood	**1,966**	**377**	**1,589**	1,799	290	1,509
Natural Gas Other[4,5]	**3,061**	**846**	**2,215**	2,975	746	2,229
Hydro	**673**	**126**	**547**	634	106	528
Wind	**946**	**155**	**791**	907	118	789
Natural Gas Storage	**677**	**92**	**585**	677	83	594
Solar[6]	**226**	**2**	**224**			
Other	**57**	**30**	**27**	134	86	48
	7,606	**1,628**	**5,978**	7,126	1,429	5,697
Under construction	**54**		**54**	136		136
	7,660	**1,628**	**6,032**	7,262	1,429	5,833
Corporate	**191**	**61**	**130**	154	54	100
	55,457	**17,851**	**37,606**	50,253	16,540	33,713

1
In 2013, the Company capitalized $37 million (2012 $32 million) relating to the equity portion of AFUDC for natural gas pipelines with a corresponding amount recorded in Interest Income and Other.

2
Includes Bison, Portland, North Baja, Tuscarora and Ventures LP.

3
Includes $2.6 billion for Keystone XL at December 31, 2013 (2012 $2 billion). Keystone XL remains subject to regulatory approvals.

4
Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $640 million and $78 million, respectively, at December 31, 2013 (2012 $601 million and $55 million, respectively). Revenues of $78 million were recognized in 2013 (2012 $73 million; 2011 $53 million) through the sale of electricity under the related PPAs.

5
Includes Halton Hills, Coolidge, Bécancour, Ocean State Power, Mackay River and other natural gas-fired facilities.

6
Includes the acquisitions in 2013 of four solar power facilities.

8. EQUITY INVESTMENTS

		Income/(Loss) from Equity Investments			Equity Investments	
	Ownership Interest at	year ended December 31			at December 31	
(millions of Canadian dollars)	December 31, 2013	2013	2012	2011	2013	2012
Natural Gas Pipelines						
Northern Border[1,2]		**66**	72	75	**557**	511
Iroquois	44.5%	**41**	41	40	**188**	174
TQM	50.0%	**13**	16	17	**76**	80
Other	Various	**25**	28	27	**62**	60
Energy						
Bruce A[3]	48.9%	**202**	(149)	33	**3,988**	4,033
Bruce B[3]	31.6%	**108**	163	77	**377**	69
ASTC Power Partnership	50.0%	**110**	40	84	**41**	42
Portlands Energy	50.0%	**31**	28	33	**343**	341
Other[4]	Various	**1**	18	29	**57**	54
Oil Pipelines						
Grand Rapids[5]	50.0%				**70**	2
		597	257	415	**5,759**	5,366

1
The results reflect a 50 per cent interest in Northern Border as a result of the Company fully consolidating TC PipeLines, LP. At December 31, 2013, TransCanada had an ownership interest in TC PipeLines, LP of 28.9 per cent (2012 and 2011 33.3 per cent) and its effective ownership of Northern Border, net of non-controlling interests, was 14.5 per cent (2012 and 2011 16.7 per cent).

2
At December 31, 2013, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company is US$118 million (2012 US$119 million) due to the fair value assessment of assets at the time of acquisition.

3
At December 31, 2013, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power is $820 million (2012 $889 million) due to the fair value assessment of assets at the time of acquisition.

4
In December 2012, TransCanada acquired the remaining 40 per cent interest in CrossAlta to bring the Company's ownership interest to 100 per cent. The results reflect the Company's 60 per cent share of equity income up to that date.

5
In October 2012, TransCanada entered into a joint venture agreement with a third party to build this pipeline system to transport crude oil and diluent between the producing area northwest of Fort McMurray and the Edmonton/Heartland market region.

Distributions received from equity investments for the year ended December 31, 2013 were $725 million (2012 $436 million; 2011 $494 million) of which $120 million (2012 $60 million; 2011 $101 million) were returns of capital and are included in Deferred Amounts and Other in the Consolidated Statement of Cash Flows. The undistributed earnings from equity investments as at December 31, 2013 were $754 million (2012 $883 million; 2011 $1,062 million).

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian dollars)	**2013**	**2012**	**2011**
Income			
Revenues	**4,989**	3,860	4,042
Operating and Other Expenses	**(3,536)**	(3,090)	(2,989)
Net Income	**1,390**	717	929
Net Income attributable to TransCanada	**597**	257	415

at December 31 (millions of Canadian dollars)	**2013**	**2012**
Balance Sheet		
Current assets	**1,500**	1,593
Non current assets	**12,158**	12,154
Current liabilities	**(1,117)**	(1,187)
Non current liabilities	**(2,507)**	(3,787)

9. RATE-REGULATED BUSINESSES

TransCanada's businesses that apply RRA currently include Canadian and U.S. natural gas pipelines and regulated U.S. natural gas storage. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities.

Canadian Regulated Operations

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

TransCanada's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the NEB. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenues for the upcoming year or multiple years. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur.

Canadian Mainline

In March 2013, TransCanada received a decision from the NEB on the comprehensive application it filed to change the business structure and the terms and conditions of service for the Canadian Mainline, including addressing tolls for 2012 and 2013 (the NEB Decision). The decision approved the 2011 revenue requirement as filed, approved tolls charged in 2012 as final with any variance between revenues and costs deferred for recovery in future years, and set tolls for 2013 through 2017 at competitive levels, fixing tolls for some services and providing unlimited pricing discretion for others. The decision established an ROE of 11.5 per cent on a deemed common equity of 40 per cent and included mechanisms to achieve the fixed tolls through the use of a Long Term Adjustment Account (LTAA) as well as the establishment of a Tolls 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. In addition, the decision provides an opportunity to generate incentive earnings by increasing revenues and reducing costs. The NEB 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. In December 2013, TransCanada filed an application with the NEB that addresses tolls moving forward.

The Canadian Mainline's 2012 results reflect an ROE of 8.08 per cent on a deemed common equity of 40 per cent and excluded incentive earnings. In 2011, the Canadian Mainline operated under a five year settlement which expired in December 2011. This settlement included an allowed ROE of 8.08 per cent on a deemed common equity of 40 per cent and also allowed for incentive earnings.

NGTL System

On November 1, 2013, the NEB approved NGTL System's 2013-2014 Revenue Requirement Settlement Application. This settlement is structured similar to the previous multi-year settlement with fixed annual operating, maintenance and administration (OM&A) costs and a 10.10 per cent ROE on a deemed common equity of 40 per cent. Any variance between fixed OM&A costs in the settlement and actual costs accrue to TransCanada. The Settlement also establishes an increase in the composite depreciation rates to 3.05 per cent in 2013 and 3.12 per cent 2014.

In September 2010, the NEB approved the NGTL System's 2010-2012 Revenue Requirement Settlement Application. The settlement provided for a 9.70 per cent ROE on a deemed common equity of 40 per cent and fixed certain annual OM&A costs during the term. Any variances between actual costs and those agreed to in the settlement accrued to TransCanada. All other costs were treated on a flow-through basis.

Other Canadian Pipelines

The Foothills operating model for 2012 and 2013 provides for recovery of all revenue requirement components on a flow-through basis. TQM operates under a model consisting of fixed and flow-through revenue requirement components for 2012 and 2013. Any variances between actual costs and those included in the fixed component accrue to TQM.

U.S. Regulated Operations

TransCanada's U.S. natural gas pipelines are "natural gas companies" operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* (NGA) and the *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The NGA 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 in interstate commerce. The Company's significant regulated U.S. natural gas pipelines are described below.

ANR

ANR's natural gas transportation and storage services are provided for under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC that was effective beginning in 1997. ANR Pipeline Company is not required to conduct a review of currently effective rates with the FERC at any time in the future but is not prohibited from filing for new rates if necessary. ANR Storage Company rates were established pursuant to a settlement approved by the FERC in August 2012. ANR Storage Company is required to file a NGA Section 4 general rate case no later than July 1, 2016. TC Offshore LLC, another ANR-related regulated entity began operating under FERC approved tariff rates on November 1, 2012. TC Offshore LLC is required to file a cost and revenue study to justify its existing approved cost-based rates after its first three years of operation.

Great Lakes

Great Lakes is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for its various services and permits Great Lakes to discount or negotiate rates on a non-discriminatory basis. Great Lakes operated under a July 2010 FERC approved rate settlement through October 2013. Effective November 1, 2013, Great Lakes operates under rates established pursuant to a settlement approved by the FERC in November 2013. The settlement provides for a moratorium between November 2013 and March 2015 during which Great Lakes and the settling parties are prohibited from taking certain actions under the NGA, including filing to adjust rates. Great Lakes is required to file for new rates to be effective no later than January 2018.

Other U.S. Pipelines

GTN and Bison are regulated by the FERC and operate in accordance with a FERC-approved tariff that establishes maximum and minimum rates for various services. Both pipelines are permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's rates were established pursuant to a settlement approved by the FERC in January 2012. GTN is required to file for new rates to be effective no later than January 2016. Bison's rates were established pursuant to its initial certificate to construct and operate the pipeline that initiated service in January 2011. Bison is required to file a cost and revenue study to justify its existing, approved cost-based rates after its first three years of operations. This is expected to be filed by April 2014.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian dollars)	**2013**	**2012**	**Remaining Recovery/ Settlement Period (years)**
Regulatory Assets			
Deferred income taxes[1]	**1,149**	1,122	n/a
Operating and debt-service regulatory assets[2]	**16**	171	1
Long Term Adjustment Account[3]	**354**	80	31
Other[4]	**258**	434	n/a
	1,777	1,807	
Less: Current portion included in Other Current Assets (Note 5)	**42**	178	
	1,735	1,629	
Regulatory Liabilities			
Foreign exchange on long-term debt[5]	**84**	150	1-16
Operating and debt-service regulatory liabilities[2]	**5**	84	1
Other[4]	**147**	134	n/a
	236	368	
Less: Current portion included in Accounts Payable and Other (Note 13)	**7**	100	
	229	268	

1
These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

2
Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar

year. Pre-tax operating results in 2013 would have been $76 million higher (2012 $50 million lower; 2011 $102 million higher) had these amounts not been recorded as regulatory assets and liabilities.

3 The LTAA was established in compliance with the NEB Decision which is comprised of amounts that are deferred and recovered in future years. The TSA, also established in the NEB Decision, includes the variances between revenue and costs. A positive balance in the TSA was realized in 2013 and, as specified in the NEB Decision, the TSA, net of incentive earnings, was combined with the LTAA on December 31, 2013.

4

Pre-tax operating results in 2013 would have been $189 million higher (2012 $13 million higher; 2011 $106 million lower) had these amounts not been recorded as regulatory assets and liabilities.

5

Foreign exchange on long-term debt of the NGTL System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of RRA, GAAP would have required the inclusion of these unrealized gains or losses in Net Income.

10. GOODWILL

The Company has recorded the following Goodwill on its acquisitions in the U.S.:

(millions of Canadian dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2012	2,693	841	3,534
Foreign exchange rate changes	(58)	(18)	(76)
Balance at December 31, 2012	2,635	823	3,458
Foreign exchange rate changes	**181**	**57**	**238**
Balance at December 31, 2013	**2,816**	**880**	**3,696**

11. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian dollars)	**2013**	**2012**
Capital projects under development	**571**	34
PPAs	**324**	376
Deferred income tax assets and charges (Note 16)	**225**	168
Loans and advances[1]	**183**	196
Fair value of derivative contracts (Note 23)	**112**	187
Employee post-retirement benefits (Note 22)	**16**	11
Other	**524**	434
	1,955	1,406

1

As at December 31, 2013, TransCanada held a $226 million (2012 $236 million) note receivable from the seller of Ravenswood which bears interest at 6.75 per cent and matures in 2040. The current portion of the note receivable of $43 million (2012 $40 million) is included in Other Current Assets.

The following amounts related to PPAs are included in Intangible and Other Assets:

at December 31 (millions of Canadian dollars)	2013 Cost	2013 Accumulated Amortization	2013 Net Book Value	2012 Cost	2012 Accumulated Amortization	2012 Net Book Value
Sheerness	**585**	**312**	**273**	585	273	312
Sundance A	**225**	**174**	**51**	225	161	64
	810	**486**	**324**	810	434	376

Amortization expense for these PPAs was $52 million for the year ended December 31, 2013 (2012 and 2011 $52 million). The expected annual amortization expense for 2014 to 2017 is $52 million and in 2018 is $39 million.

Sundance A

In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by TransAlta Corporation. In January 2011, TransCanada disputed this claim which was then subject to arbitration. In July 2012, TransCanada received the binding arbitration decision. The arbitration panel determined that the PPA should not be terminated and ordered TransAlta Corporation to return Units 1 and 2 to service. Unit 1 returned to service in September 2013, followed by Unit 2 in October 2013.

Between December 2010 and March 2012, TransCanada recorded revenues and costs related to the Sundance A PPA as though the outages of Units 1 and 2 were interruptions of supply. As a result of the above decision, TransCanada recorded a $50 million pre-tax charge in 2012, comprised of $20 million and $30 million previously accrued in 2011 and 2012, respectively, as these amounts were no longer recoverable.

12. NOTES PAYABLE

	2013		2012	
(millions of Canadian dollars)	**Outstanding December 31**	**Weighted Average Interest Rate per Annum at December 31**	**Outstanding December 31**	**Weighted Average Interest Rate per Annum at December 31**
Canadian dollars	**751**	**1.2%**	803	1.2%
U.S. dollars (2013 US$1,025; 2012 US$1,480)	**1,091**	**0.3%**	1,472	0.4%
	1,842		2,275	

Notes Payable consists of commercial paper issued by TransCanada PipeLines Limited (TCPL), TransCanada PipeLine USA Ltd. (TCPL USA), TransCanada American Investments Ltd. (TAIL) and TransCanada Keystone Pipeline, LP (TC Keystone) and drawings on line-of-credit and demand facilities. The TC Keystone facility expired in November 2013. The cost to maintain the facility was $1.4 million in 2013 (2012 $1 million; 2011 $4 million).

At December 31, 2013, total committed revolving and demand credit facilities of $6.2 billion (2012 $5.3 billion) were available. When drawn, interest on the lines of credit is charged at prime rates of Canadian chartered and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31, 2013					year ended December 31		
					2013	**2012**	**2011**
Amount	**Unused Capacity**	**Borrower**	**For**	**Matures**	**Cost to maintain**		
					(millions of Canadian dollars)		
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility	December 2018	4	4	2
US$1 billion	US$0.8 billion	TCPL USA	Committed, syndicated, revolving, extendible TCPL USA credit facility, guaranteed by TCPL	November 2014	1	1	4
US$1 billion	US$1 billion	TAIL	Committed, syndicated, revolving, extendible TAIL credit facility, guaranteed by TCPL	November 2014			
$1.1 billion	$0.3 billion	TCPL	Supports the issuance of letters of credit and provides additional liquidity	Demand			

13. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian dollars)	2013	2012
Trade payables	**866**	923
Fair value of derivative contracts (Note 23)	**357**	283
Dividends payable	**338**	320
Deferred Income Tax Liabilities (Note 16)	**26**	
Regulatory Liabilities (Note 9)	**7**	100
Liabilities related to assets held for sale (Note 6)	**5**	
Other	**556**	718
	2,155	2,344

14. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian dollars)	2013	2012
Employee post-retirement benefit (Note 22)	**244**	482
Fair value of derivative contracts (Note 23)	**255**	186
Asset retirement obligations	**83**	72
Guarantees (Note 26)	**18**	17
Other	**56**	125
	656	882

15. LONG-TERM DEBT

Outstanding loan amounts (millions of Canadian dollars)	**Maturity Dates**	**2013** Outstanding December 31	**2013** Interest Rate[1]	**2012** Outstanding December 31	**2012** Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2014 to 2020	**874**	**10.9%**	874	10.9%
U.S. dollars (2013 and 2012 US$400)	2021	**425**	**9.9%**	398	9.9%
Medium-Term Notes					
Canadian dollars	2014 to 2041	**4,799**	**5.7%**	4,549	5.9%
Senior Unsecured Notes					
U.S. dollars (2013 US$12,276; 2012 US$10,126)	2015 to 2043	**13,027**	**5.0%**	10,057	5.6%
		19,125		15,878	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2014 to 2024	**378**	**11.5%**	382	11.5%
U.S. dollars (2013 and 2012 US$200)	2023	**213**	**7.9%**	199	7.9%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. dollars (2013 and 2012 US$33)	2026	**34**	**7.5%**	32	7.5%
		1,129		1,117	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2013 and 2012 US$432)	2021 to 2025	**459**	**8.9%**	430	8.9%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. dollars (2013 and 2012 US$325)	2015 to 2035	**346**	**5.5%**	323	5.5%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2013 US$380; 2012 US$312)	2017	**404**	**1.4%**	310	1.5%
Medium-Term Loan					
U.S. dollars (2013 US$500)	2018	**532**	**1.4%**		
Senior Unsecured Notes					
U.S. dollars (2013 and 2012 US$350)	2021	**372**	**4.7%**	348	4.7%
		1,308		658	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					

Senior Unsecured Notes					
U.S. dollars (2013 US$335; 2012 US$354)	2018 to 2030	**356**	**7.8%**	352	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Secured Notes					
U.S. dollars (2013 US$24; 2012 US$27)	2017	**25**	**4.0%**	27	4.0%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[2]					
U.S. dollars (2013 US$110; 2012 US$129)	2018	**117**	**6.1%**	128	6.1%
		22,865		18,913	
Less: Current Portion of Long-Term Debt		**973**		894	
		21,892		18,019	

1 Interest rates are the effective interest rates except for those pertaining to Long-Term Debt issued for the Company's Canadian regulated operations, in which case the weighted average interest rate is presented as approved by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 Secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the Long-Term Debt of the Company for the next five years are approximately as follows:

(millions of Canadian dollars)	2014	2015	2016	2017	2018
Principal repayments on Long-Term Debt	973	1,659	2,092	862	1,632

TransCanada PipeLines Limited

In October 2013, TCPL issued US$625 million and US$625 million of Senior Unsecured Notes maturing October 16, 2023 and October 16, 2043, respectively, and bearing interest at 3.75 per cent and 5.00 per cent, respectively.

In August 2013, TCPL retired US$500 million of 5.05 per cent Senior Unsecured Notes.

In July 2013, TCPL issued US$500 million of London Interbank Offered Rate-based floating rate notes maturing on June 30, 2016, bearing interest at an initial annual rate of 0.95 per cent.

Also in July 2013, TCPL issued $450 million and $300 million of Medium-Term Notes maturing on July 19, 2023 and November 15, 2041, respectively, and bearing interest at rates of 3.69 and 4.55 per cent per annum, respectively.

In June 2013, TCPL retired US$350 million of 4.0 per cent Senior Unsecured Notes.

In January 2013, TCPL issued US$750 million of Senior Unsecured Notes maturing January 15, 2016 and bearing interest at 0.75 per cent.

In August 2012, TCPL issued US$1 billion of Senior Unsecured Notes maturing August 1, 2022 and bearing interest at 2.5 per cent.

In May 2012, TCPL retired US$200 million of 8.625 per cent Senior Unsecured Notes.

In March 2012, TCPL issued US$500 million of Senior Unsecured Notes maturing March 2, 2015 and bearing interest at 0.875 per cent.

In November 2011, TCPL issued $500 million and $250 million of Medium-Term Notes maturing November 15, 2021 and November 15, 2041, respectively, and bearing interest at 3.65 per cent and 4.55 per cent, respectively.

In May 2011, TCPL retired $60 million of 9.5 per cent Medium-Term Notes.

In January 2011, TCPL retired $300 million of 4.3 per cent Medium-Term Notes.

NOVA Gas Transmission Ltd.

In December 2012, NOVA Gas Transmission Ltd. (NGTL) retired US$175 million of 8.5 per cent Debentures.

Debentures issued by NGTL in the amount of $225 million have retraction provisions that entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made to December 31, 2013.

TransCanada PipeLine USA Ltd.

In February 2013, TCPL USA's US$300 million committed, syndicated, revolving credit facility matured.

TC PipeLines, LP

During 2013, TC PipeLines, LP made drawings on its syndicated revolving credit facility of US$437 million, and repayments of US$369 million. At December 31, 2013, US$380 million (2012 US$312 million) was outstanding on the facility.

In July 2013, TC PipeLines, LP entered into and fully drew upon a new term loan agreement with a syndicate of lenders for a US$500 million medium-term loan, maturing July 1, 2018, and bearing interest at a floating rate calculated on a base rate plus an applicable margin. A portion of the loan proceeds were used to partially fund

the acquisition of a 45 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) as further described in Note 25.

In December 2011, TC PipeLines, LP repaid a maturing US$300 million term loan with a draw of US$312 million under the syndicated revolving credit facility.

In June 2011, TC PipeLines, LP issued US$350 million of 4.65 per cent Senior Unsecured Notes due 2021.

In May 2011, TC PipeLines, LP made draws of US$61 million on a bridge loan facility and US$125 million on its syndicated revolving credit facility.

Interest Expense

year ended December 31 (millions of Canadian dollars)	**2013**	**2012**	**2011**
Interest on Long-Term Debt	**1,216**	1,190	1,154
Interest on Junior Subordinated Notes	**65**	63	63
Interest on short-term debt	**12**	16	16
Capitalized interest	**(287)**	(300)	(302)
Amortization and other financial charges[1]	**(21)**	7	6
	985	976	937

1 Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and changes in the fair value of derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $985 million in 2013 (2012 $966 million; 2011 $926 million) on Long-Term Debt and Junior Subordinated Notes, net of interest capitalized on construction projects.

16. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian dollars)	**2013**	**2012**	**2011**
Current			
Canada	**27**	167	212
Foreign	**16**	14	(2)
	43	181	210
Deferred			
Canada	**245**	69	139
Foreign	**323**	216	226

	568	285	365
Income Tax Expense	**611**	466	575

Geographic Components of Income

year ended December 31 (millions of Canadian dollars)	2013	2012	2011
Canada	**1,224**	842	1,176
Foreign	**1,298**	1,096	1,109
Income before Income Taxes	**2,522**	1,938	2,285

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian dollars)	2013	2012	2011
Income before Income Taxes	**2,522**	1,938	2,285
Federal and provincial statutory tax rate	**25.0%**	25.0%	26.5%
Expected income tax expense	**631**	485	605
Income tax differential related to regulated operations	**(13)**	41	42
Higher/(lower) effective foreign tax rates	**46**	1	(5)
Income from equity investments and non-controlling interests	**(41)**	(40)	(45)
Tax legislation change	**(25)**		
Other	**13**	(21)	(22)
Actual Income Tax Expense	**611**	466	575

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian dollars)	2013	2012
Deferred Income Tax Assets		
Operating loss carryforwards	**826**	1,024
Deferred amounts	**223**	112
Other	**128**	239
	1,177	1,375
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, equipment and PPAs	**4,245**	3,817
Equity investments	**682**	578
Taxes on future revenue requirement	**291**	283
Unrealized foreign exchange gains on long-term debt	**35**	159
Other	**170**	96
	5,423	4,933
Net Deferred Income Tax Liabilities	**4,246**	3,558

The above deferred tax amounts have been classified in the Consolidated Balance Sheet as follows:

at December 31 (millions of Canadian dollars)	2013	2012
Deferred Income Tax Assets		
Other Current Assets (Note 5)	**119**	290
Intangible and Other Assets (Note 11)	**225**	168
	344	458
Deferred Income Tax Liabilities		
Accounts Payable and Other (Note 13)	**26**	
Deferred Income Tax Liabilities	**4,564**	4,016
	4,590	4,016
Net Deferred Income Tax Liabilities	**4,246**	3,558

At December 31, 2013, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,026 million (2012 $865 million) for federal and provincial purposes in Canada, which expire from 2014 to 2033.

At December 31, 2013, the Company has recognized the benefit of unused net operating loss carryforwards of US$1,432 million (2012 US$2,174 million) for federal purposes in the U.S., which expire from 2028 to 2033.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2013 by approximately $182 million (2012 $144 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $202 million, net of refunds, were made in 2013 (2012 payments, net of refunds, of $190 million; 2011 refunds, net of payments made, of $84 million).

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian dollars)	2013	2012	2011
Unrecognized tax benefits at beginning of year	**49**	52	62
Gross increases tax positions in prior years	**3**	2	9
Gross decreases tax positions in prior years	**(28)**	(6)	(7)
Gross increases tax positions in current year	**2**	9	11
Lapses of statute of limitations	**(3)**	(8)	(23)
Unrecognized tax benefits at end of year	**23**	49	52

TransCanada recognized a favourable income tax adjustment of approximately $25 million due to the enactment of certain Canadian Federal tax legislation in June 2013.

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

TransCanada and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2008. Substantially all material U.S. federal income tax matters have been concluded for years through 2007 and U.S. state and local income tax matters through 2007.

TransCanada's practice is to recognize interest and penalties related to income tax uncertainties in Income Tax Expense. Income Tax Expense for the year ended December 31, 2013 reflects an increase of $1 million of Interest Expense and nil for penalties (2012 $2 million reversal of Interest Expense and nil for penalties; 2011 $12 million reversal for Interest Expense and nil for penalties). At December 31, 2013, the Company had $6 million accrued for Interest Expense and nil accrued for penalties (December 31, 2012 $5 million accrued for Interest Expense and nil accrued for penalties).

17. JUNIOR SUBORDINATED NOTES

		2013		2012	
Outstanding loan amount (millions of Canadian dollars)	**Maturity Date**	**Outstanding December 31**	**Effective Interest Rate**	**Outstanding December 31**	**Effective Interest Rate**
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2013 and 2012 US$1,000)	2067	**1,063**	**6.5%**	994	6.5%

Junior Subordinated Notes of US$1.0 billion mature in 2067 and bear interest at 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate plus 221 basis points. The Company has the option to defer payment of interest for periods of up to 10 years without giving rise to a default and without permitting acceleration of payment under the terms of the Junior Subordinated Notes. However, the Company would be prohibited from paying dividends during any such deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and other obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017, at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes.

18. NON-CONTROLLING INTERESTS

The Company's Non-Controlling Interests included in the Consolidated Balance Sheet were as follows:

at December 31 (millions of Canadian dollars)	**2013**	**2012**
Non-controlling interest in TC PipeLines, LP[1]	**1,323**	953
Preferred shares of TCPL	**194**	389
Non-controlling interest in Portland[2]	**94**	83
	1,611	1,425

The Company's Non-Controlling Interests included in the Consolidated Statement of Income were as follows:

year ended December 31 (millions of Canadian dollars)	**2013**	**2012**	**2011**
Non-controlling interest in TC PipeLines, LP[1]	**93**	91	101
Preferred share dividends of TCPL	**20**	22	22
Non-controlling interest in Portland[2]	**12**	5	6
	125	118	129

1
In May 2013, the non-controlling interest in TC PipeLines, LP increased from 66.7 per cent to 71.1 per cent due to the issuance of equity to non-controlling interests in TC PipeLines, LP. In July 2013, TransCanada sold 45 per cent interests in GTN LLC and Bison LLC to TC PipeLines, LP (See Note 25). The non-controlling interest in TC PipeLines, LP from January 2010 to May 2011 was 61.8 per cent and 66.7 per cent from May 2011 to May 2013.

2
The non-controlling interest in Portland as at December 31, 2013 represented the 38.3 per cent interest not owned by TransCanada (2012 and 2011 38.3 per cent).

Preferred Shares of TCPL

at December 31	**Number of Shares**	**Annual Dividend Rate per Share**	**Redemption Price per Share**	**2013**	**2012**
	(thousands)			(millions of Canadian dollars)[1]	(millions of Canadian dollars)[1]
Cumulative First Preferred Shares of Subsidiary					
Series U	4,000	$2.80	$50.00		195
Series Y	4,000	$2.80	$50.00	**194**	194
				194	389

1
Net of underwriting underwriting commissions and deferred income taxes.

In October 2013, TCPL redeemed all of the four million outstanding 5.60 per cent Cumulative Redeemable First Preferred Shares Series U at a price of $50 per share plus $0.5907 representing accrued and unpaid dividends to the redemption date.

On January 27, 2014, TCPL announced the redemption of all of the four million outstanding Cumulative Redeemable First Preferred Shares Series Y shares at $50 per share, plus accrued and unpaid dividends. Refer to Note 27 for further details.

Cash Dividends

Cash dividends of $22 million were paid on the Series U and Series Y preferred shares in 2013 (2012 and 2011 $22 million).

In 2013, TransCanada received fees of $3 million from TC PipeLines, LP (2012 $3 million; 2011 $2 million) and $7 million from Portland (2012 and 2011 $7 million) for services provided.

19. COMMON SHARES

	Number of Shares	**Amount**
	(thousands)	(millions of Canadian dollars)
Outstanding at January 1, 2011	696,230	11,745
Dividend reinvestment and share purchase plan	5,371	202
Exercise of options	2,260	64
Outstanding at December 31, 2011	703,861	12,011
Exercise of options	1,600	58
Outstanding at December 31, 2012	705,461	12,069
Exercise of options	**1,980**	**80**
Outstanding at December 31, 2013	**707,441**	**12,149**

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Net Income per Share

Net income per share is calculated by dividing Net Income Attributable to Common Shares by the weighted average number of common shares outstanding. During the year, the weighted average number of common shares outstanding were used to calculate basic and diluted earnings per share. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

Weighted Average Common Shares Outstanding (millions)	**2013**	**2012**	**2011**
Basic	**706.7**	704.6	701.6
Diluted	**707.7**	705.7	702.8

Stock Options

	Number of Options	**Weighted Average Exercise Prices**	**Options Exercisable**
	(thousands)		(thousands)
Outstanding at January 1, 2011	8,406	$32.57	6,458
Granted	970	$38.02	
Exercised	(2,260)	$25.86	
Forfeited	(16)	$35.83	
Outstanding at December 31, 2011	7,100	$35.44	5,165
Granted	1,978	$42.03	
Exercised	(1,600)	$33.13	

Forfeited	(44)	$36.55	
Outstanding at December 31, 2012	7,434	$37.69	4,588
Granted	**1,939**	**$47.09**	
Exercised	**(1,980)**	**$36.12**	
Outstanding at December 31, 2013	**7,393**	**$40.57**	**3,954**

Stock options outstanding at December 31, 2013 were as follows:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	**Number of Options**	**Weighted Average Exercise Price**	**Weighted Average Remaining Contractual Life**	**Number of Options**	**Weighted Average Exercise Price**	**Weighted Average Remaining Contractual Life**
	(thousands)		(years)	(thousands)		(years)
$30.10 to $36.26	1,725	$33.72	2.5	1,725	$33.72	2.5
$36.90 to $41.65	1,781	$38.52	3.7	1,516	$38.60	3.5
$41.95 to $45.29	1,948	$42.03	5.2	690	$42.03	5.2
$47.09	1,939	$47.09	6.1	23	$47.09	6.1
	7,393	$40.57	4.3	3,954	$37.12	3.1

An additional 10.5 million common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2013. The weighted average fair value of options granted to purchase common shares under the Company's Stock Option Plan was determined to be $5.74 for the year ended December 31, 2013 (2012 $5.08; 2011 $2.94). The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment.

The Company used a binomial model for determining the fair value of options granted applying the following weighted average assumptions:

	2013	2012	2011
Expected life (years)	**6.0**	5.9	4.0
Interest rate	**1.7%**	1.6%	2.1%
Volatility[1]	**18%**	19%	14%
Dividend yield	**3.7%**	4.2%	4.3%
Forfeiture rate	**15%**	15%	15%

1 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional Paid-In Capital, was $6 million in 2013 (2012 and 2011 $5 million).

The following table summarizes additional stock option information:

Year Ended December 31 (millions of Canadian dollars unless noted otherwise)	2013	2012	2011
Total intrinsic value of options exercised	**$25**	$18	$34
Fair value of options that have vested	**$65**	$49	$42
Total options vested	**1.3 million**	1.0 million	0.9 million

As at December 31, 2013, the aggregate intrinsic value of the total options exercisable was $45 million and the total intrinsic value of options outstanding was $59 million.

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to provide the Board with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase two common shares of the Company for the then current market price of one.

Cash Dividends

The following table summarizes cash dividends paid:

year ended December 31 (millions of Canadian dollars except per share amounts)	**2013**	**2012**	**2011**
Cash dividends paid, net of Dividend Reinvestment Plan	**1,285**	1,226	961
Cash dividends paid per common share	**$1.82**	$1.74	$1.66

Dividend Reinvestment Plan

Under the Company's Dividend Reinvestment Plan (DRP), eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL can reinvest their dividends and make optional cash payments to obtain TransCanada common shares. Commencing with the dividends declared in April 2011, dividends payable to shareholders who participate in the DRP were satisfied with common shares purchased on the open market determined on the basis of the weighted average purchase price of such common shares. Previously, common shares issued in lieu of cash dividends under the DRP were issued from treasury at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2010, was reduced to two per cent commencing with the dividends declared in February 2011 and was eliminated completely in April 2011. In 2011, TransCanada issued 5.4 million common shares from treasury in accordance with the DRP in lieu of making cash dividend payments of $202 million.

20. PREFERRED SHARES

at December 31	**Number of Shares Authorized and Outstanding**	**Annual Dividend Rate per Share**	**Redemption Price per Share**	**2013**	**2012**
	(thousands)			(millions of Canadian dollars)[1]	(millions of Canadian dollars)[1]
Cumulative First Preferred Shares					
Series 1	22,000	$1.15	$25.00	**539**	539
Series 3	14,000	$1.00	$25.00	**343**	343
Series 5	14,000	$1.10	$25.00	**342**	342
Series 7	24,000	$1.00	$25.00	**589**	
				1,813	1,224

1 Net of underwriting commissions and deferred income taxes.

The holders of the Series 1 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.15 per share, payable quarterly, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.92 per cent. The Series 1 preferred shares are redeemable by TransCanada on December 31, 2014 and on December 31 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends.

The Series 1 preferred shareholders have the right to convert their shares into Series 2 cumulative redeemable first preferred shares on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of

Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent.

The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly, for the initial five-year period ending June 30, 2015. The dividend rate will reset on June 30, 2015 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends.

The Series 3 preferred shareholders have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.28 per cent.

The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.10 per share, payable quarterly, for the initial five-and-a-half-year period ending January 30, 2016. The dividend rate will reset on January 30, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends.

The Series 5 preferred shareholders have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.54 per cent.

In March 2013, TransCanada completed a public offering of 24 million Series 7 cumulative redeemable first preferred shares at a price of $25 per share, resulting in gross proceeds of $600 million. The holders of the Series 7 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly, for the initial six-year period ending April 30, 2019. The dividend rate will reset on April 30, 2019 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 2.38 per cent. The Series 7 preferred shares are redeemable by TransCanada on April 30, 2019 and on April 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends.

The Series 7 preferred shareholders have the right to convert their shares into Series 8 cumulative redeemable first preferred shares on April 30, 2019 and on April 30 of every fifth year thereafter. The holders of Series 8 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 2.38 per cent.

Cash Dividends

The Company has paid preferred share cash dividends as follows:

	2013		2012		2011	
at December 31 (millions of Canadian dollars, except per share amounts)	**Cash Dividend Payments[1]**	**Annual Dividend Rate per Share**	**Cash Dividend Payments**	**Annual Dividend Rate per Share**	**Cash Dividend Payments** (net of DRP)	**Annual Dividend Rate per Share**
Cumulative First Preferred Shares						
Series 1	**25**	**$1.15**	25	$1.15	25	$1.15
Series 3	**14**	**$1.00**	14	$1.00	14	$1.00
Series 5	**16**	**$1.10**	16	$1.10	16	$1.10
Series 7	**16[2]**	**$1.00[2]**				
	71		55		55	

1 At December 31, 2013, there were dividends declared but not yet paid of $10 million (2012 $4 million) included in Accounts Payable and Other (Note 13) which was paid on January 30, 2014.

2 For the year ended December 31, 2013, the cash dividend rate was prorated at $0.65 per share.

21. OTHER COMPREHENSIVE INCOME AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of OCI including Non-Controlling Interests and the related tax effects are as follows:

year ended December 31, 2013 (millions of Canadian dollars)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains and losses on net investments in foreign operations	**269**	**114**	**383**
Change in fair value of net investment hedges	**(323)**	**84**	**(239)**
Change in fair value of cash flow hedges	**121**	**(50)**	**71**
Reclassification to Net Income of gains and losses on cash flow hedges	**60**	**(19)**	**41**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**96**	**(29)**	**67**
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**34**	**(11)**	**23**
Other comprehensive income on Equity Investments	**313**	**(79)**	**234**

Other comprehensive income	**570**	**10**	**580**

year ended December 31, 2012 (millions of Canadian dollars)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains and losses on net investments in foreign operations	(97)	(32)	(129)
Change in fair value of net investment hedges	59	(15)	44
Change in fair value of cash flow hedges	61	(13)	48
Reclassification to Net Income of gains and losses on cash flow hedges	219	(81)	138
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(104)	31	(73)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	22		22
Other comprehensive loss on Equity Investments	(93)	23	(70)
Other comprehensive income/(loss)	67	(87)	(20)

year ended December 31, 2011 (millions of Canadian dollars)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains and losses on net investments in foreign operations	108	29	137
Change in fair value of net investment hedges	(101)	28	(73)
Change in fair value of cash flow hedges	(318)	106	(212)
Reclassification to Net Income of gains and losses on cash flow hedges	224	(77)	147
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(119)	30	(89)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	13	(3)	10
Other comprehensive loss on Equity Investments	(94)	3	(91)
Other comprehensive (loss)/income	(287)	116	(171)

The changes in AOCI by component is as follows:

	Currency translation adjustments	Cash flow hedges	Pension and OPEB plan adjustments	Equity Investments	Total[1]
AOCI Balance at January 1, 2011	(683)	(226)	(157)	(177)	(1,243)
Other comprehensive income/(loss) before reclassifications[2]	40	(213)	(89)	(83)	(345)
Amounts reclassified from Accumulated Other Comprehensive Loss		137	10	(8)	139
Net current period other comprehensive income/(loss)	40	(76)	(79)	(91)	(206)
AOCI Balance at December 31, 2011	(643)	(302)	(236)	(268)	(1,449)
Other comprehensive income before reclassifications[2]	(64)	48	(73)	(67)	(156)
Amounts reclassified from Accumulated Other Comprehensive Loss		138	22	(3)	157
Net current period other comprehensive (loss)/income	(64)	186	(51)	(70)	1
AOCI Balance at December 31, 2012	(707)	(116)	(287)	(338)	(1,448)
Other comprehensive income before reclassifications[2]	**78**	**71**	**67**	**219**	**435**
Amounts reclassified from Accumulated Other Comprehensive Loss[3]		**41**	**23**	**15**	**79**
Net current period other comprehensive income	**78**	**112**	**90**	**234**	**514**
AOCI Balance at December 31, 2013	**(629)**	**(4)**	**(197)**	**(104)**	**(934)**

1

All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2

OCI before reclassifications on currency translation adjustments is net of non-controlling interest gains of $66 million in 2013 (2012 $21 million losses; 2011 $35 million gains).

3

Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $81 million ($50 million, net of tax) at December 31, 2013. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

Details about reclassifications out of AOCI into the Consolidated Statement of Income are as follows:

year ended December 31 (millions of Canadian dollars)	**Amounts reclassified from accumulated other comprehensive loss[1]** **2013**	**2012**	**Affected line item in the consolidated statement of income**
Cash flow hedges			
Power and Natural Gas	**(44)**	(201)	Revenue (Energy)
Interest	**(16)**	(18)	Interest Expense
	(60)	(219)	Income before Income Taxes
	19	81	Income Tax Expense
	(41)	(138)	Net of tax
Pension and other post-retirement plan adjustments			
Amortization of net loss[2]	**(34)**	(22)	Total before tax
	11		Income before Income Taxes
	(23)	(22)	Net of tax
Equity Investments			
Equity Income	**(20)**	5	Income from Equity Investments
	5	(2)	Income Tax Expense
	(15)	3	Net of tax

1 All amounts in parentheses indicate expenses to the Consolidated Statement of Income.

2 These Accumulated Other Comprehensive Loss components are included in the computation of net benefit cost. Refer to Note 22 for additional detail.

22. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. Past service costs are amortized over the expected average remaining service life of employees, which is approximately nine years (2012 nine years; 2011 eight years).

The Company also provides its employees with a savings plan in Canada, DC Plans consisting of 401(k) Plans in the U.S., and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which was approximately 11 years at December 31, 2013 (2012 and 2011 12 years). In 2013, the Company expensed $29 million (2012 $24 million, 2011 $23 million) for the savings plan and DC Plans.

Total cash payments for employee post-retirement benefits, consisting of cash contributed by the Company were as follows:

year ended December 31 (millions of Canadian dollars)	**2013**	**2012**	**2011**
DB Plans	**79**	83	62
Other post-retirement benefit plans	**6**	7	8
Savings and DC Plans	**29**	24	23
	114	114	93

In 2013, the Company provided a $59 million letter of credit to the Canadian DB Plan (2012 $48 million; 2011 $27 million), resulting in a total of $134 million provided to the Canadian DB Plan under letters of credit at December 31, 2013.

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2014 and the next required valuation will be as at January 1, 2015.

at December 31	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
(millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Change in Benefit Obligation[1]				
Benefit obligation beginning of year	**2,142**	1,836	**186**	170
Service cost	**84**	66	**2**	2
Interest cost	**96**	94	**7**	8
Employee contributions	**4**	4		1
Benefits paid	**(83)**	(79)	**(7)**	(9)
Actuarial (gain)/loss	**(39)**	227	**(2)**	16
Foreign exchange rate changes	**20**	(6)	**5**	(2)
Benefit obligation end of year	**2,224**	2,142	**191**	186
Change in Plan Assets				
Plan assets at fair value beginning of year	**1,825**	1,656	**32**	29
Actual return on plan assets	**313**	165	**2**	4
Employer contributions[2]	**79**	83	**6**	7
Employee contributions	**4**	4		1
Benefits paid	**(83)**	(79)	**(7)**	(9)
Foreign exchange rate changes	**14**	(4)	**2**	
Plan assets at fair value end of year	**2,152**	1,825	**35**	32
Funded Status Plan Deficit	**(72)**	(317)	**(156)**	(154)

1 The benefit obligation for the Company's pension benefit plan represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.

2 Excludes $134 million in letters of credit provided to Canadian DB Plan for funding purposes.

The amounts recognized in the Company's Balance Sheet for its DB plans and other post-retirement benefits plans are as follows:

at December 31	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
(millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Intangible and Other Assets (Note 11)			**16**	11
Other Long-Term Liabilities (Note 14)	**(72)**	(317)	**(172)**	(165)

	(72)	(317)	**(156)**	(154)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Projected benefit obligation[1]	**(2,224)**	(2,142)	**(172)**	(165)
Plan assets at fair value	**2,152**	1,825		
Funded Status Deficit	**(72)**	(317)	**(172)**	(165)

1 The projected benefit obligation for the pension benefit plan differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The accumulated benefit obligation for all DB pension plans at December 31, 2013 is $2,039 million (2012 $1,966 million).

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

at December 31 (millions of Canadian dollars)	**2013**	**2012**
Accumulated benefit obligation	**(2,039)**	(1,966)
Plan assets at fair value	**2,152**	1,825
Funded Status Surplus/(Deficit)	**113**	(141)

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

at December 31 (millions of Canadian dollars)	**2013**	**2012**
Accumulated benefit obligation	**(569)**	(1,966)
Plan assets at fair value	**537**	1,825
Funded Status Deficit	**(32)**	(141)

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

Asset Category

	Percentage of Plan Assets		Target Allocations[1]
at December 31	**2013**	**2012**	**2013**

Debt securities	**31%**	36%	**25% to 35%**
Equity securities	**69%**	64%	**50% to 70%**
Alternatives			**5% to 15%**
	100%	100%	

1 Target allocations were revised in November 2013 and the investment mix is being adjusted accordingly.

Debt and equity securities include the Company's debt and common shares as follows:

at December 31			**Percentage of Plan Assets**	
(millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Debt securities	**2**	2	**0.1%**	0.1%
Equity securities	**2**	3	**0.1%**	0.2%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities, as well as alternative assets such as infrastructure, private equity and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques, such as option pricing models and extrapolation using significant inputs, which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. For further information on the fair value hierarchy, refer to Note 23.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy.

at December 31	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
(millions of Canadian dollars)	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Asset Category										
Cash and Cash Equivalents	**17**	17					**17**	17	**1%**	1%
Equity Securities:										
Canadian	**474**	400	**170**	113			**644**	513	**29%**	28%
U.S.	**423**	309	**37**	38			**460**	347	**21%**	19%
International	**36**	31	**330**	263			**366**	294	**17%**	16%
Global			**14**	13			**14**	13	**1%**	
Fixed Income Securities:										
Canadian Bonds:										
Federal			**304**	314			**304**	314	**14%**	17%
Provincial			**154**	161			**154**	161	**7%**	9%
Municipal			**6**	5			**6**	5		
Corporate			**77**	65			**77**	65	**3%**	4%
U.S. Bonds:										
State			**33**	33			**33**	33	**2%**	2%
Corporate			**48**	45			**48**	45	**2%**	2%
International:										
Corporate			**20**	9			**20**	9	**1%**	
Mortgage Backed			**26**	22			**26**	22	**1%**	1%
Other Investments:										
Private Equity Funds					**18**	19	**18**	19	**1%**	1%
	950	757	**1,219**	1,081	**18**	19	**2,187**	1,857	**100%**	100%

The following table presents the net change in the Level III fair value category:

(millions of Canadian dollars, pre-tax)	Private Equity Funds
Balance at December 31, 2011	20
Realized and unrealized losses	(1)
Balance at December 31, 2012	19
Purchases and sales	**(4)**
Realized and unrealized gains	**3**
Balance at December 31, 2013	**18**

The Company's expected funding contributions in 2014 are approximately $70 million for the DB Plans, approximately $6 million for the other post-retirement benefit plans and approximately $34 million for the savings plan and DC Plans. In addition, the Company expects to provide a $47 million letter of credit to the Canadian DB Plan.

The following are estimated future benefit payments, which reflect expected future service:

(millions of Canadian dollars)	Pension Benefits	Other Post-Retirement Benefits
2014	93	9
2015	100	9
2016	106	10
2017	112	11
2018	118	11
2019 to 2023	684	58

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2013. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		**Other Post-Retirement Benefit Plans**	
at December 31	**2013**	**2012**	**2013**	**2012**
Discount rate	**4.95%**	4.35%	**5.00%**	4.35%
Rate of compensation increase	**3.15%**	3.15%		

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

	Pension Benefit Plans			**Other Post-Retirement Benefit Plans**		
year ended December 31	**2013**	**2012**	**2011**	**2013**	**2012**	**2011**
Discount rate	**4.35%**	5.05%	5.55%	**4.35%**	5.10%	5.60%
Expected long-term rate of return on plan assets	**6.70%**	6.70%	6.95%	**4.60%**	6.40%	6.40%
Rate of compensation increase	**3.15%**	3.15%	3.10%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

A 7.5 per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2014 measurement purposes. The rate was assumed to decrease gradually to five per cent by

2020 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of Canadian dollars)	**Increase**	**Decrease**
Effect on total of service and interest cost components	1	
Effect on post-retirement benefit obligation	18	(15)

The Company's net benefit cost is as follows:

at December 31	**Pension Benefit Plans**			**Other Post-Retirement Benefit Plans**		
(millions of Canadian dollars)	**2013**	**2012**	**2011**	**2013**	**2012**	**2011**
Service cost	**84**	66	54	**2**	2	2
Interest cost	**96**	94	91	**7**	8	9
Expected return on plan assets	**(120)**	(113)	(114)	**(2)**	(2)	(2)
Amortization of actuarial loss	**30**	18	10	**2**	1	1
Amortization of past service cost	**2**	2	2		1	
Amortization of regulatory asset	**30**	19	12	**1**	1	1
Amortization of transitional obligation related to regulated business				**2**	2	2
Net Benefit Cost Recognized	**122**	86	55	**12**	13	13

Pre-tax amounts recognized in AOCI were as follows:

	2013		**2012**		**2011**	
at December 31 (millions of Canadian dollars)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss	**236**	**32**	362	33	282	29
Prior service cost	**3**	**1**	5	2	7	2
	239	**33**	367	35	289	31

The estimated net loss and prior service cost for the DB Plans that will be amortized from AOCI into net periodic benefit cost in 2014 are $36 million and $2 million, respectively. The estimated net loss and prior service cost for the other post-retirement plans that will be amortized from AOCI into net periodic benefit cost in 2014 is $2 million and nil, respectively.

Pre-tax amounts recognized in OCI were as follows:

	2013		**2012**		**2011**	
at December 31	**Pension Benefits**	**Other Post-Retirement**	**Pension Benefits**	**Other Post-Retirement**	**Pension Benefits**	**Other Post-Retirement**

(millions of Canadian dollars)		**Benefits**		**Benefits**		**Benefits**
Amortization of net loss from AOCI to OCI	**(30)**	**(2)**	(19)	(1)	(10)	(1)
Amortization of prior service costs from AOCI to OCI	**(2)**		(2)		(2)	
Funded status adjustment	**(96)**		99	5	113	6
	(128)	**(2)**	78	4	101	5

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk and counterparty credit risk, and has strategies, policies and limits in place to manage the impact of these risks on earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to assist in managing the exposure to market risk that results from these activities. These derivative contracts may consist of the following:

- Forwards and futures contracts contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to manage the impact of volatility in foreign exchange rates and commodity prices.

- Swaps contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

- Options contractual agreements that convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity and natural gas. A number of strategies are used to manage these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to manage operational and price risks in its asset portfolio.

- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin.

- The Company's power sales commitments are fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.

- The Company enters into offsetting or back-to-back positions using derivative instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

Natural Gas Storage Commodity Price Risk

TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Unrealized gains and losses on fair value adjustments recorded each period on these forward contracts are not necessarily representative of the amounts that will be realized on settlement.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and interest rates.

A portion of TransCanada's earnings from its Natural Gas Pipelines, Oil Pipelines and Energy segments is generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's net income. As the Company's U.S. dollar-denominated operations continue to grow, exposure to changes in currency rates increases, and some of this foreign exchange impact is partially offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to other U.S. dollar-denominated transactions including those that arise on some of the Company's regulated assets. Certain of the realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

Net Investment in Foreign Operations

The Company hedges its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options.

U.S. Dollar-Denominated Debt Designated as a Net Investment Hedge

at December 31 (millions of Canadian dollars unless noted otherwise)	**2013**	**2012**
Carrying value	**14,200**	11,100
	(US 13,400)	(US 11,200)
Fair value	**16,000**	14,300
	(US 15,000)	(US 14,400)

Derivatives Designated as a Net Investment Hedge

	2013		2012	
at December 31 (millions of Canadian dollars unless noted otherwise)	**Fair Value[1]**	**Notional or Principal Amount**	Fair Value[1]	Notional or Principal Amount
U.S. dollar cross-currency interest rate swaps (maturing 2014 to 2019)[2]	**(201)**	**US 3,800**	82	US 3,800
U.S. dollar foreign exchange forward contracts (maturing 2014)	**(11)**	**US 850**		US 250
	(212)	**US 4,650**	82	US 4,050

1 Fair values approximate carrying values.

2 In 2013, net realized gains of $29 million (2012 gains of $30 million) related to the interest component of cross-currency swap settlements are included in Interest Expense.

The balance sheet classification of the fair value of derivatives used to hedge the Company's net investment in foreign operations is as follows:

at December 31 (millions of Canadian dollars)	**2013**	2012
Other Current Assets (Note 5)	**5**	71
Intangible and Other Assets (Note 11)		47
Accounts Payable and Other (Note 13)	**(50)**	(6)
Other Long-Term Liabilities (Note 14)	**(167)**	(30)
	(212)	82

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the related contract or agreement with the Company.

The Company manages its exposure to this potential loss by using recognized credit management techniques, including:

- Dealing with creditworthy counterparties a significant amount of the Company's credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- Setting limits on the amount TransCanada can transact with any one counterparty the Company monitors and manages the concentration of risk exposure with any one counterparty, and reduces the exposure when needed and when it is allowed under the terms of the contracts
- Using contract netting arrangements and obtaining financial assurances, such as guarantees, and letters of credit or cash, when they are deemed necessary.

There is no guarantee, however, that these techniques will protect the Company from material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the Balance Sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets and notes, loans and advances receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2013, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

At December 31, 2013, the Company had a credit risk concentration of $240 million (2012 $259 million) due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

TransCanada has significant credit and performance exposures to financial institutions as they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Financial Instruments

All financial instruments, including both derivative and non-derivative instruments, are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's normal purchases and normal sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Fair Value of Non-Derivative Financial Instruments

The fair value of the Company's notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-Term Debt is estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers. The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative instruments.

Certain non-derivative financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangible and Other Assets, Notes Payable, Accounts Payable and Other, Accrued Interest and Other Long-Term Liabilities have carrying amounts that equal their fair value due to the nature of the item or the short time to maturity and would be classified in Level II of the fair value hierarchy.

Balance Sheet Presentation of Non-Derivative Financial Instruments

The following table details the fair value of the non-derivative financial instruments, excluding those where carrying amounts equal fair value, and would be classified in Level II of the fair value hierarchy:

	2013		2012	
at December 31 (millions of Canadian dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Notes receivable and other[1]	**226**	**269**	237	286
Available for sale assets[2]	**47**	**47**	44	44
Current and Long-Term Debt[3,4] (Note 15)	**(22,865)**	**(26,134)**	(18,913)	(24,573)
Junior Subordinated Notes (Note 17)	**(1,063)**	**(1,093)**	(994)	(1,054)
	(23,655)	**(26,911)**	(19,626)	(25,297)

1 Notes receivable are included in Other Current Assets and Intangible and Other Assets on the Consolidated Balance Sheet.

2 Available for sale assets are included in Intangible and Other Assets on the Consolidated Balance Sheet.

3 Long-Term Debt is recorded at amortized cost, except for US$200 million (2012   US$350 million) that is attributed to hedged risk and recorded at fair value.

4

Consolidated Net Income in 2013 included losses of $5 million (2012 losses of $10 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$200 million of Long-Term Debt at December 31, 2013 (2012 US$350 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2013:

Contractual Principal Repayments of Non-Derivative Financial Liabilities

at December 31 (millions of Canadian dollars)	**Total**	**2014**	**2015 and 2016**	**2017 and 2018**	**2019 and Thereafter**
Notes Payable (Note 12)	1,842	1,842			
Long-Term Debt (Note 15)	22,865	973	3,751	2,494	15,647
Junior Subordinated Notes (Note 17)	1,063				1,063
	25,770	2,815	3,751	2,494	16,710

Interest Payments on Non-Derivative Financial Liabilities

at December 31 (millions of Canadian dollars)	**Total**	**2014**	**2015 and 2016**	**2017 and 2018**	**2019 and Thereafter**
Long-Term Debt (Note 15)	16,798	1,254	2,315	2,111	11,118
Junior Subordinated Notes (Note 17)	3,614	68	135	135	3,276
	20,412	1,322	2,450	2,246	14,394

Fair Value of Derivative Instruments

The fair value of foreign exchange and interest rate derivatives have been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives and available for sale assets has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

Where possible, derivative instruments are designated as hedges, but in some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment and are accounted for at fair value with changes in fair value recorded in Net Income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

Balance Sheet Presentation of Derivative Instruments

The balance sheet classification of the fair value of the derivative instruments is as follows:

at December 31 (millions of Canadian dollars)	**2013**	2012
Other Current Assets (Note 5)	**395**	259
Intangible and Other Assets (Note 11)	**112**	187
Accounts Payable and Other (Note 13)	**(357)**	(283)
Other Long-Term Liabilities (Note 14)	**(255)**	(186)

	(105)	(23)

2013 Derivative Instruments Summary

The following summary does not include hedges of our net investment in foreign operations.

(millions of Canadian dollars unless noted otherwise)	Power	Natural Gas	Foreign Exchange	Interest
Derivative Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$265**	**$73**	**$**	**$8**
Liabilities	**($280)**	**($72)**	**($12)**	**($7)**
Notional Values				
Volumes[3]				
Purchases	**29,301**	**88**		
Sales	**28,534**	**60**		
Canadian dollars				**400**
U.S. dollars			**US 1,015**	**US 100**
Net unrealized gains/(losses) in the year[4]	**$19**	**$17**	**($10)**	**$**
Net realized losses in the year[4]	**($49)**	**($13)**	**($9)**	**$**
Maturity dates	**2014-2017**	**2014-2016**	**2014**	**2014-2016**
Derivative Instruments in Hedging Relationships[5,6]				
Fair Values[2]				
Assets	**$150**	**$**	**$**	**$6**
Liabilities	**($22)**	**$**	**($1)**	**($1)**
Notional Values				
Volumes[3]				
Purchases	**9,758**			
Sales	**6,906**			
U.S. dollars			**US 16**	**US 350**
Net realized (losses)/gains in the year[4]	**($19)**	**($2)**	**$**	**$5**
Maturity dates	**2014-2018**		**2014**	**2015-2018**

1

All derivative instruments held for trading have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

2

Fair value equals carrying value.

3

Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

4

Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in Energy Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative instruments held for trading are included net in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Energy Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

5
All hedging relationships are designated as cash flow hedges except for interest rate derivative instruments designated as fair value hedges with a fair value of $5 million and a notional amount of US$200 million. In 2013, net realized gains on fair value hedges were $6 million and were included in Interest Expense. In 2013, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

6
In 2013, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

2012 Derivative Instruments Summary

The following summary does not include hedges of our net investment in foreign operations.

(millions of Canadian dollars unless noted otherwise)	Power	Natural Gas	Foreign Exchange	Interest
Derivative Instruments Held for Trading[1]				
Fair Values[2]				
Assets	$139	$88	$1	$14
Liabilities	($176)	($104)	($2)	($14)
Notional Values				
Volumes[3]				
Purchases	31,135	83		
Sales	31,066	65		
Canadian dollars				620
U.S. dollars			US 1,408	US 200
Net unrealized (losses)/gains in the year[4]	($30)	$2	($1)	$
Net realized gains/(losses) in the year[4]	$5	($10)	$26	$
Maturity dates	2013-2017	2013-2016	2013	2013-2016
Derivative Instruments in Hedging Relationships[5,6]				
Fair Values[2]				
Assets	$76	$	$	$10
Liabilities	($97)	($2)	($38)	$
Notional Values				
Volumes[3]				
Purchases	15,184	1		
Sales	7,200			
U.S. dollars			US 12	US 350
Cross-currency			136/US 100	
Net realized (losses)/gains in the year[4]	($130)	($23)	$	$7
Maturity dates	2013-2018	2013	2013-2014	2013-2015

1 All derivative instruments held for trading have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

2 Fair value equals carrying value.

3 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

4 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in Energy Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative instruments held for trading are included net in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Energy Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

5

All hedging relationships are designated as cash flow hedges except for interest rate derivative instruments designated as fair value hedges with a fair value of $10 million and a notional amount of US$350 million. In 2012, net realized gains on fair value hedges were $7 million and were included in Interest Expense. In 2012, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

6

In 2012, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in Cash Flow Hedging Relationships

The following table presents the components of OCI (Note 21) related to derivatives in cash flow hedging relationships:

year ended December 31 (millions of Canadian dollars, pre-tax)	**2013**	**2012**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Power	**117**	83
Natural Gas	**(1)**	(21)
Foreign Exchange	**5**	(1)
	121	61
Reclassification of gains on derivative instruments from AOCI to Net Income (effective portion)[1]		
Power[2]	**40**	147
Natural Gas[2]	**4**	54
Interest	**16**	18
	60	219
Gains on derivative instruments recognized in Net Income (ineffective portion)		
Power	**8**	7
	8	7

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.

2 Reported within Energy Revenues on the Consolidated Statement of Income.

Offsetting of Derivative Instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TransCanada has no master netting agreements, however, similar contracts are entered into containing rights of offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis in the balance sheet. The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at December 31, 2013 (millions of Canadian dollars)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset[1]**	**Net amounts**
Derivative Asset			
Power	**415**	**(277)**	**138**
Natural Gas	**73**	**(61)**	**12**

Foreign exchange	**5**	**(5)**	
Interest	**14**	**(2)**	**12**
	507	**(345)**	**162**
Derivative Liability			
Power	**(302)**	**277**	**(25)**
Natural gas	**(72)**	**61**	**(11)**
Foreign exchange	**(230)**	**5**	**(225)**
Interest	**(8)**	**2**	**(6)**
	(612)	**345**	**(267)**

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to all financial arrangements, including the derivative instruments presented above, as at December 31, 2013, the Company had provided cash collateral of $67 million and letters of credit of $85 million to its counterparties. The Company held $11 million in cash collateral and $32 million in letters of credit from counterparties on asset exposures at December 31, 2013.

The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis as at December 31, 2012:

at December 31, 2012 (millions of Canadian dollars)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset[1]**	**Net amounts**
Derivative Asset			
Power	215	(132)	83
Natural Gas	88	(83)	5
Foreign exchange	119	(37)	82
Interest	24	(6)	18
	446	(258)	188
Derivative Liability			
Power	(273)	132	(141)
Natural gas	(106)	83	(23)
Foreign exchange	(76)	37	(39)
Interest	(14)	6	(8)
	(469)	258	(211)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to all financial arrangements, including the derivative instruments presented above as at December 31, 2012, the Company had provided cash collateral of $189 million and letters of credit of $45 million to its counterparties. The Company held $2 million in cash collateral and $5 million in letters of credit from counterparties on asset exposures at December 31, 2012.

Credit Risk Related Contingent Features of Derivative Instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade.

Based on contracts in place and market prices at December 31, 2013, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $16 million (2012 $37 million), for which the Company has provided collateral in the normal course of business of nil (2012 nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2013, the Company would have been required to provide additional collateral of $16 million (2012 $37 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.
Level II	Valuation based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers. This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and power and natural gas commodity derivatives where fair value is determined using the market approach. Transfers between Level I and Level II would occur when there is a change in market circumstances.
Level III	Valuation of assets and liabilities are measured using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. This category includes long-dated commodity transactions in certain markets where liquidity is low. Long-term electricity prices are estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which we operate. Model inputs include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices are based on a view of future natural gas supply and demand, as well as exploration and development costs. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas is expected to or may result in a lower fair value measurement of contracts included in Level III. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which significant inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2013, are categorized as follows:

at December 31, 2013 (millions of Canadian dollars, pre-tax)	**Quoted prices in active markets Level I[1]**	**Significant other observable inputs Level II[1]**	**Significant unobservable inputs Level III[1]**	**Total**
Derivative Instrument Assets:				
Power commodity contracts		**411**	**4**	**415**
Natural gas commodity contracts	**48**	**25**		**73**
Foreign exchange contracts		**5**		**5**
Interest rate contracts		**14**		**14**
Derivative Instrument Liabilities:				
Power commodity contracts		**(299)**	**(3)**	**(302)**
Natural gas commodity contracts	**(50)**	**(22)**		**(72)**
Foreign exchange contracts		**(230)**		**(230)**
Interest rate contracts		**(8)**		**(8)**
Non-Derivative Financial Instruments:				
Available for sale assets		**47**		**47**
	(2)	**(57)**	**1**	**(58)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2013.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2012, are categorized as follows:

at December 31, 2012 (millions of Canadian dollars, pre-tax)	**Quoted prices in active markets Level I[1]**	**Significant other observable inputs Level II[1]**	**Significant unobservable inputs Level III[1]**	**Total**
Derivative Instrument Assets:				
Power commodity contracts		213	2	215
Natural gas commodity contracts	75	13		88
Foreign exchange contracts		119		119
Interest rate contracts		24		24
Derivative Instrument Liabilities:				
Power commodity contracts		(269)	(4)	(273)
Natural gas commodity contracts	(95)	(11)		(106)
Foreign exchange contracts		(76)		(76)
Interest rate contracts		(14)		(14)
Non-Derivative Financial Instruments:				
Available for sale assets		44		44
	(20)	43	(2)	21

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended

December 31, 2012.

The following table presents the net change in fair value of derivative assets and liabilities classified as Level III of the fair value hierarchy:

(millions of Canadian dollars, pre-tax)	2013	2012
Balance at beginning of year	**(2)**	(15)
Settlements		(1)
Transfers out of Level III	**(2)**	(21)
Total (losses)/gains included in Net Income	**(1)**	11
Total gains included in OCI	**6**	24
Balance at end of year[1]	**1**	(2)

1 Energy Revenues include unrealized gains or losses attributed to derivatives in the Level III category that were still held at December 31, 2013 of nil (2012 $1 million).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $2 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at December 31, 2013.

24. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian dollars)	2013	2012	2011
(Increase)/decrease in Accounts Receivable	**(54)**	67	(15)
(Increase)/decrease in Inventories	**(30)**	27	3
Decrease/(increase) in Other Current Assets	**40**	66	(27)
(Decrease)/increase in Accounts Payable and Other	**(290)**	127	266
Increase in Accrued Interest	**8**		8
(Increase)/Decrease in Operating Working Capital	**(326)**	287	235

25. ACQUISITIONS AND DISPOSITIONS

Energy

Ontario Solar

In 2011, TransCanada agreed to purchase nine Ontario solar facilities with a combined capacity of 86 MW from Canadian Solar Solutions Inc. for approximately $500 million. Under the terms of the agreement, TransCanada will purchase each facility once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the Ontario Power Authority as part of the Feed-in Tariff program in Ontario.

In 2013, TransCanada acquired the first four of these solar power facilities for $216 million. TransCanada measured the assets and liabilities acquired at fair value with substantially all of the purchase price allocated to Plant, Property and Equipment and no Goodwill was recorded.

TransCanada anticipates the remaining facilities will come into service and be acquired in 2014.

CrossAlta

In December 2012, TransCanada purchased BP's 40 per cent interest in the assets of the Crossfield Gas Storage facility and BP's interest in CrossAlta Gas Storage & Services Ltd. (collectively CrossAlta) for $214 million in cash, net of cash acquired, resulting in the Company owning and operating 100 per cent of these operations.

The Company measured the assets and liabilities acquired at fair value and the transaction resulted in no Goodwill. Upon acquisition, TransCanada began consolidating CrossAlta. Prior to the acquisition, TransCanada applied equity accounting to its 60 per cent ownership interest in CrossAlta.

Natural Gas Pipelines

TC PipeLines, LP

In July 2013, TransCanada completed the sale of a 45 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$1.05 billion, which included US$146 million of long-term debt for 45 per cent of GTN LLC debt outstanding, plus normal closing adjustments. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

In May 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at a price of US$43.85 per unit, resulting in gross proceeds of approximately US$388 million and net proceeds of US$373 million after unit issuance costs. TransCanada contributed approximately US$8 million to maintain its two per cent general partnership interest and did not purchase any other units. Upon completion of this offering, TransCanada's ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent and an after-tax dilution gain of $29 million ($47 million pre-tax) was recorded in Additional Paid-In Capital.

In May 2011, TransCanada completed the sale of a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$605 million which included US$81 million of long-term debt, or 25 per cent of GTN LLC's outstanding debt, plus normal closing adjustments.

In May 2011, TC PipeLines, LP completed a public offering of 7,245,000 common units at a price of US$47.58 per unit, resulting in gross proceeds of approximately US$345 million and net proceeds of US$331 million after unit issuance costs. TransCanada contributed approximately US$7 million to maintain its two per cent general partnership interest and did not purchase any other units. As a result of the common units offering, TransCanada's ownership in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent and an after-tax dilution gain of $30 million ($50 million pre-tax) was recorded in Additional Paid-In Capital.

26. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating Leases

Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services and equipment are approximately as follows:

year ended December 31 (millions of Canadian dollars)	**Minimum Lease Payments**	**Amounts Recoverable under Sub-leases**	**Net Payments**
2014	98	8	90
2015	97	7	90
2016	92	5	87
2017	86	5	81
2018	82	3	79
2019 and thereafter	325		325
	780	28	752

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to 10 years. Net rental expense on operating leases in 2013 was $98 million (2012 $84 million; 2011 $79 million).

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability and other factors. TransCanada's share of payments under the PPAs in 2013 was $242 million (2012 $238 million; 2011 $309 million). The generating capacities and expiry dates of the PPAs are as follows:

	MW	**Expiry Date**
Sundance A	560	December 31, 2017
Sheerness	756	December 31, 2020

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Other Commitments

Capital expenditure commitments include signed contracts related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

At December 31, 2013, TransCanada was committed to Natural Gas Pipelines capital expenditures totaling approximately $1.3 billion (2012 $1.3 billion), primarily related to construction costs related to the NGTL System and other natural gas pipeline projects.

At December 31, 2013, the Company was committed to Oil Pipelines capital expenditures totaling approximately $2.5 billion (2012 $1.7 billion), primarily related to construction costs of Keystone XL and Grand Rapids.

At December 31, 2013, the Company was committed to Energy capital expenditures totaling approximately $0.1 billion (2012 $0.1 billion), primarily related to capital costs of the Napanee Generating Station.

At December 31, 2013, the Company was committed to purchase the remaining five solar facilities from Canadian Solar Solutions Inc. for approximately $280 million.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2013, the Company had accrued approximately $32 million (2012 $37 million; 2011 $49 million) related to operating facilities, which represents the present value of the estimated future amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations of Bruce A related to a sublease agreement and certain other financial obligations. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been included in Other Long-Term Liabilities. Information regarding the Company's guarantees is as follows:

		2013		2012
year ended December 31 (millions of Canadian dollars)	**Term**	**Potential Exposure[1]**	**Carrying Value**	