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 PipeLines Limited (TCPL 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 report of KPMG LLP outlines the scope of its examination and its opinion on the consolidated financial statements.

Russell K. Girling President and Chief Executive Officer	**Donald R. Marchand** Executive Vice-President and Chief Financial Officer

February 19, 2014

Independent Auditors' Report of Registered Public Accounting Firm

TO THE SHAREHOLDERS OF TRANSCANADA PIPELINES LIMITED

We have audited the accompanying consolidated financial statements of TransCanada PipeLines Limited, 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 PipeLines Limited 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.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 19, 2014

Consolidated statement of income

year ended December 31 (millions of Canadian dollars)	**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)	**1,046**	1,037	1,078
Interest income and other	**(72)**	(125)	(89)
	974	912	989
Income before Income Taxes	**2,499**	1,917	2,178
Income Tax Expense (Note 16)			
Current	**43**	185	194
Deferred	**562**	276	352
	605	461	546
Net Income	**1,894**	1,456	1,632
Net Income Attributable to Non-Controlling Interests (Note 18)	**105**	96	107
Net Income Attributable to Controlling Interests	**1,789**	1,360	1,525
Preferred Share Dividends (Note 20)	**20**	22	22
Net Income Attributable to Common Shares	**1,769**	1,338	1,503

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	**1,894**	1,456	1,632
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	**2,474**	1,436	1,461
Comprehensive Income Attributable to Non-Controlling Interests	**171**	75	142
Comprehensive Income Attributable to Controlling Interests	**2,303**	1,361	1,319
Preferred Share Dividends	**20**	22	22
Comprehensive Income Attributable to Common Shares	**2,283**	1,339	1,297

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	**1,894**	1,456	1,632
Depreciation and amortization	**1,485**	1,375	1,328
Deferred income taxes (Note 16)	**562**	276	352
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)	**(334)**	287	207
Net cash provided by operations	**3,643**	3,546	3,567
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)	**(1,308)**	(1,248)	(1,185)
Distributions paid to non-controlling interests	**(146)**	(113)	(109)
Advances (to)/from affiliates, net	**(297)**	(235)	(2,090)
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	**899**	269	2,401
Partnership units of subsidiary issued, net of issue costs (Note 25)	**384**	–	321
Preferred shares redeemed (Note 20)	**(200)**	–	–
Net cash provided by/(used in) financing activities	**1,807**	(367)	(536)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**28**	(15)	4
Increase/(Decrease) in Cash and Cash Equivalents	**358**	(92)	(19)
Cash and Cash Equivalents			
Beginning of year	**537**	629	648
Cash and Cash Equivalents			
End of year	**895**	537	629

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	**895**	537
Accounts receivable	**1,165**	1,089
Due from affiliates (Note 27)	**2,721**	2,889
Inventories	**251**	224
Other (Note 5)	**845**	992
	5,877	5,731
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)	**1,953**	1,405
	56,626	51,302
LIABILITIES		
Current Liabilities		
Notes payable (Note 12)	**1,842**	2,275
Accounts payable and other (Note 13)	**2,141**	2,340
Due to affiliates (Note 27)	**1,439**	1,904
Accrued interest	**389**	370
Current portion of long-term debt (Note 15)	**973**	894
	6,784	7,783
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
	35,188	31,962
EQUITY		
Common shares, no par value (Note 19)	**15,205**	14,306
Issued and outstanding: December 31, 2013 – 757 million shares		
December 31, 2012 – 738 million shares		
Preferred shares (Note 20)	**194**	389
Additional paid-in capital	**431**	400
Retained earnings	**5,125**	4,657
Accumulated other comprehensive loss (Note 21)	**(934)**	(1,448)
Controlling interests	**20,021**	18,304
Non-controlling interests (Note 18)	**1,417**	1,036
	21,438	19,340
	56,626	51,302

Commitments, Contingencies and Guarantees (Note 26)

Subsequent Events (Note 28)

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	**14,306**	14,037	11,636
Proceeds from shares issued (Note 19)	**899**	269	2,401
Balance at end of year	**15,205**	14,306	14,037
Preferred Shares			
Balance at beginning of year	**389**	389	389
Redemption of preferred shares	**(195)**	–	–
Balance at end of year	**194**	389	389
Additional Paid-In Capital			
Balance at beginning of year	**400**	394	359
Other	**7**	6	5
Dilution impact from TC PipeLines, LP units issued (Note 25)	**29**	–	30
Redemption of preferred shares	**(5)**	–	–
Balance at end of year	**431**	400	394
Retained Earnings			
Balance at beginning of year	**4,657**	4,561	4,236
Net income attributable to controlling interests	**1,789**	1,360	1,525
Common share dividends	**(1,301)**	(1,242)	(1,178)
Preferred share dividends	**(20)**	(22)	(22)
Balance at end of year	**5,125**	4,657	4,561
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	**20,021**	18,304	17,932
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,036**	1,076	768
Net income attributable to non-controlling interests			
TC PipeLines, LP	**93**	91	101
Portland	**12**	5	6
Other comprehensive income/(loss) attributable to non-controlling interests	**66**	(21)	35
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**384**	–	321
Decrease in TCPL's ownership of TC PipeLines, LP	**(47)**	–	(50)
Distributions declared to non-controlling interests	**(146)**	(113)	(109)
Foreign exchange and other	**19**	(2)	4
Balance at end of year	**1,417**	1,036	1,076
Total Equity	**21,438**	19,340	19,008

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TCPL'S BUSINESS

TransCanada PipeLines Limited (TCPL or the Company) is a wholly owned subsidiary of TransCanada Corporation (TransCanada) and 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, TCPL 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, TCPL 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 TCPL:
  - a 46.4 per cent interest in Great Lakes, in which TCPL 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 TCPL has a 14.5 per cent effective ownership interest through TC PipeLines, LP;
  - a 70 per cent interest in GTN, in which TCPL 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 TCPL 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 TCPL 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 TCPL has a 28.9 per cent effective ownership interest through TC PipeLines, LP.

TCPL 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). TCPL does not operate this pipeline.

TCPL 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).

TCPL 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).

TCPL 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.

TCPL 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).

TCPL 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).

TCPL 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, TCPL 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.

TCPL is currently constructing a natural gas-fired power plant at Ontario Power Generation's Lennox site in Greater Napanee, Ontario (Napanee).

TCPL 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 TCPL 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. TCPL 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. TCPL 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, TCPL 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 TCPL'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. TCPL'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 TCPL 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 TCPL 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 TCPL 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 TCPL are not attributed a value for accounting purposes. When required, TCPL 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.

Other Compensation Programs

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					(1,046)
Interest Income and Other					72
Income before Income Taxes					2,499
Income Tax Expense					(605)
Net Income					1,894
Net Income Attributable to Non-Controlling Interests					(105)
Net Income Attributable to Controlling Interests					1,789
Preferred Share Dividends					(20)
Net Income Attributable to Common Shares					1,769

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					(1,037)
Interest Income and Other					125
Income before Income Taxes					1,917
Income Tax Expense					(461)
Net Income					1,456
Net Income Attributable to Non-Controlling Interests					(96)
Net Income Attributable to Controlling Interests					1,360
Preferred Share Dividends					(22)
Net Income Attributable to Common Shares					1,338

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					(1,078)
Interest Income and Other					89
Income before Income Taxes					2,178
Income Tax Expense					(546)
Net Income					1,632
Net Income Attributable to Non-Controlling Interests					(107)
Net Income Attributable to Controlling Interests					1,525
Preferred Share Dividends					(22)
Net Income Attributable to Common Shares					1,503

1 Commencing in February 2011, TCPL 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	**4,461**	4,450
	56,626	51,302

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)	**117**	285
Assets held for sale (Note 6)	**85**	–
Regulatory Assets (Note 9)	**42**	178
Other	**206**	270
	845	992

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 28) for further details.

7. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian dollars)	2013 Cost	2013 Accumulated Depreciation	2013 Net Book Value	2012 Cost	2012 Accumulated Depreciation	2012 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, TCPL 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, TCPL 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, TCPL 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 TCPL	**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

TCPL'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.

TCPL'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, TCPL 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, TCPL 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 TCPL. 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 TCPL. 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
TCPL'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)	**223**	167
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
	1,953	1,405

1 As at December 31, 2013, TCPL 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:

	2013			2012		
at December 31 (millions of Canadian dollars)	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	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, TCPL disputed this claim which was then subject to arbitration. In July 2012, TCPL 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, TCPL 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, TCPL 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

(millions of Canadian dollars)	2013 Outstanding December 31	2013 Weighted Average Interest Rate per Annum at December 31	2012 Outstanding December 31	2012 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 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	**328**	316
Deferred Income Tax Liabilities (Note 16)	**26**	–
Regulatory Liabilities (Note 9)	**7**	100
Liabilities related to assets held for sale (Note 6)	**5**	–
Other	**552**	718
	2,141	2,340

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	**73**	77	157
Capitalized interest	**(287)**	(300)	(302)
Amortization and other financial charges[1]	**(21)**	7	6
	1,046	1,037	1,078

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 $1,047 million in 2013 (2012 – $1,027 million; 2011 – $1,069 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**	171	196
Foreign	**16**	14	(2)
	43	185	194
Deferred			
Canada	**239**	60	126
Foreign	**323**	216	226
	562	276	352
Income Tax Expense	**605**	461	546

Geographic Components of Income

year ended December 31 (millions of Canadian dollars)	2013	2012	2011
Canada	**1,201**	821	1,069
Foreign	**1,298**	1,096	1,109
Income before Income Taxes	**2,499**	1,917	2,178

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian dollars)	2013	2012	2011
Income before Income Taxes	**2,499**	1,917	2,178
Federal and provincial statutory tax rate	**25.0%**	25.0%	26.5%
Expected income tax expense	**625**	479	577
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**	(20)	(23)
Actual Income Tax Expense	**605**	461	546

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	**124**	233
	1,173	1,369
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	**4,250**	3,564

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)	**117**	285
Intangible and Other Assets (Note 11)	**223**	167
	340	452
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	**4,250**	3,564

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 $206 million, net of refunds, were made in 2013 (2012 – payments, net of refunds, of $175 million; 2011 – refunds, net of payments made, of $85 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	**45**	48	58
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	**19**	45	48

TCPL 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, TCPL 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.

TCPL 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.

TCPL's practice is to recognize interest and penalties related to income tax uncertainties in Income Tax Expense. There were no amounts recognized for interest and penalties for the year ended December 31, 2013 (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 $5 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
Non-controlling interest in Portland[2]	**94**	83
	1,417	1,036

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
Non-controlling interest in Portland[2]	**12**	5	6
	105	96	107

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, TCPL 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 TCPL (2012 and 2011 – 38.3 per cent).

In 2013, TCPL 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	675,547	11,636
Issuance of common shares for cash	56,325	2,401
Outstanding at December 31, 2011	731,872	14,037
Issuance of common shares for cash	6,509	269
Outstanding at December 31, 2012	738,381	14,306
Issuance of common shares for cash	**18,733**	**899**
Outstanding at December 31, 2013	**757,114**	**15,205**

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Restriction on Dividends

Certain terms of the Company's preferred share and debt instruments can limit the amount of dividends the Company can pay on preferred and common shares. At December 31, 2013 these terms limit the company from paying dividends in excess of $1.3 billion (2012 – $1.0 billion; 2011 – $2.6 billion). Under the agreements, TCPL can adjust this limit throughout the year if required, at is sole discretion, without incurring significant costs.

Cash Dividends

The following table summarizes cash dividends paid:

year ended December 31 **(millions of Canadian dollars)**	**2013**	**2012**	**2011**
Cash dividends paid	1,285	1,226	1,163

20. PREFERRED SHARES

at December 31	Number of Shares Authorized and Outstanding	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 U	4,000	$2.80	$50.00	–	195
Series Y	4,000	$2.80	$50.00	**194**	194
				194	389

1 Net of underwriting commissions and deferred income taxes.

In October 2013, TCPL redeemed all of the four million outstanding 5.60 percent 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 at $50 per share, plus accrued and unpaid dividends. Refer to Note 28 for further details.

Cash Dividends

Cash Dividends of $22 million were paid on the series U and the series Y preferred shares in each of 2013, 2012 and 2011.

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 (millions of Canadian dollars)	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
	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 (millions of Canadian dollars)	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
	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 (millions of Canadian dollars)	Pension Benefit Plans 2013	Pension Benefit Plans 2012	Other Post-Retirement Benefit Plans 2013	Other Post-Retirement Benefit Plans 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

at December 31	Percentage of Plan Assets 2013	Percentage of Plan Assets 2012	Target Allocations[1] 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 (millions of Canadian dollars)	2013	2012	Percentage of Plan Assets 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 (millions of Canadian dollars)	Quoted Prices in Active Markets (Level I) 2013	2012	Significant Other Observable Inputs (Level II) 2013	2012	Significant Unobservable Inputs (Level III) 2013	2012	Total 2013	2012	Percentage of Total Portfolio 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 (millions of Canadian dollars)	**Pension Benefit Plans** 2013	2012	2011	**Other Post-Retirement Benefit Plans** 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:

at December 31 (millions of Canadian dollars)	**2013** Pension Benefits	**2013** Other Post-Retirement Benefits	**2012** Pension Benefits	**2012** Other Post-Retirement Benefits	**2011** Pension Benefits	**2011** 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:

at December 31 (millions of Canadian dollars)	**2013** Pension Benefits	**2013** Other Post-Retirement Benefits	**2012** Pension Benefits	**2012** Other Post-Retirement Benefits	**2011** Pension Benefits	**2011** Other Post-Retirement 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

TCPL 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 TCPL'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. TCPL 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

TCPL 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. TCPL 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 TCPL'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 TCPL'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.

TCPL 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 (US 13,400)**	11,100 (US 11,200)
Fair value	**16,000 (US 15,000)**	14,300 (US 14,400)

Derivatives Designated as a Net Investment Hedge

at December 31 (millions of Canadian dollars unless noted otherwise)	2013 Fair Value[1]	2013 Notional or Principal Amount	2012 Fair Value[1]	2012 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 TCPL 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.

TCPL'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.

TCPL 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, Due from Affiliates, Intangible and Other Assets, Notes Payable, Accounts Payable and Other, Due to Affiliates, 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 TCPL'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. TCPL 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	**(60)**	50	(34)
(Increase)/decrease in Inventories	**(30)**	27	3
Decrease/(increase) in Other Current Assets	**40**	64	(15)
(Decrease)/increase in Accounts Payable and Other	**(291)**	146	243
Increase in Accrued Interest	**7**	–	10
(Increase)/Decrease in Operating Working Capital	**(334)**	287	207

25. ACQUISITIONS AND DISPOSITIONS

Energy

Ontario Solar

In 2011, TCPL 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, TCPL 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, TCPL acquired the first four of these solar power facilities for $216 million. TCPL 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.

TCPL anticipates the remaining facilities will come into service and be acquired in 2014.

CrossAlta

In December 2012, TCPL 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, TCPL began consolidating CrossAlta. Prior to the acquisition, TCPL applied equity accounting to its 60 per cent ownership interest in CrossAlta.

Natural Gas Pipelines

TC PipeLines, LP

In July 2013, TCPL 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. TCPL 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, TCPL'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, TCPL 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. TCPL 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, TCPL'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).

TCPL'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. TCPL'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

TCPL 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, TCPL 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

TCPL 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.

TCPL 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

TCPL 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, TCPL 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 TCPL 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**	**Potential Exposure[1]**	**Carrying Value**
Bruce Power	Ranging to 2019[2]	**629**	**8**	897	10
Other jointly owned entities	Ranging to 2040	**51**	**10**	89	7
		680	**18**	986	17

1 TCPL's share of the potential estimated current or contingent exposure.

2 Except for one guarantee with no termination date.

27. RELATED PARTY TRANSACTIONS

The following amounts are included in Due from Affiliates:

(millions of Canadian dollars)	Maturity Date	2013 Outstanding December 31	2013 Effective Interest Rate	2012[2] Outstanding December 31	2012[2] Effective Interest Rate
Discount Notes[1]	2014	**2,721**	**1.3%**	2,889	1.4%
		2,721		2,889	

1 Interest on the discount notes is equivalent to current commercial paper rates.

2 Balances in 2012 were previously reported net with amounts Due to Affiliates on the Consolidated Balance Sheet. To conform with our current reporting, we have adjusted the presentation to show the amounts on a gross basis.

In 2013, Interest Income included $38 million as a result of inter-corporate borrowing (2012 – $41 million; 2011 – $35 million).

In 2013, Accounts Receivables included $43 million due from various affiliates of TCPL.

The following amounts are included in Due to Affiliates:

(millions of Canadian dollars)	Maturity Date	2013 Outstanding December 31	2013 Effective Interest Rate	2012[3] Outstanding December 31	2012[3] Effective Interest Rate
Credit Facility[1]		**574**	**3.0%**	1,240	3.0%
Credit Facility[2]	2014	**865**	**3.8%**	664	3.8%
		1,439		1,904	

1 TCPL's demand revolving credit arrangement with TransCanada is $2.0 billion (or a U.S. dollar equivalent). This facility bears interest at the Royal Bank of Canada prime rate per annum, or the U.S base rate per annum. This facility may be terminated at any time at TransCanada's option.

2 TransCanada has an unsecured $3.5 billion credit facility with a subsidiary of TCPL. Interest on this facility is charged at Reuters prime rate plus 75 basis points.

3 Balances in 2012 were previously reported net with amounts Due from Affiliates on the Consolidated Balance Sheet. To conform with our current reporting, we have adjusted the presentation to show the amounts on a gross basis.

In 2013, Interest expense included $62 million of interest charges as a result of inter-corporate borrowing (2012 – $61 million; 2011 – $140 million).

At December 31, 2013, Accounts Payable included $1 million of interest payable to TransCanada (December 31, 2012 – $2 million).

The Company made interest payments of $62 million to TransCanada in 2013 (2012 – $62 million; 2011 – $144 million).

28. SUBSEQUENT EVENTS

Common Shares

On January 20, 2014, TCPL issued 9.1 million common shares to TransCanada resulting in proceeds of $440 million.

Cancarb Asset Sale

On January 20, 2014, TCPL reached an agreement to sell Cancarb Limited and its related power generation facility for aggregate gross proceeds of $190 million, subject to closing adjustments. The transaction is expected to close late in the first quarter of 2014, subject to various approvals. The related assets were classified as assets held for sale at December 31, 2013 (Note 6).

Preferred Share Redemption

On January 27, 2014, TCPL announced the redemption of all of the four million outstanding 5.60 per cent Cumulative Redeemable First Preferred Shares Series Y on March 5, 2014 at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends to such redemption date. The total par value of the outstanding Series Y Shares is $200 million and they carry an aggregate of $11.2 million in annualized dividends.