2013
ANNUAL REPORT

FORTIS INC.

Utility and Generation Operations

Regulated

Gas ◆

FortisBC *British Columbia*
Central Hudson *New York State*
UNS Energy* *Arizona*

Electric ■

FortisBC *British Columbia*
Central Hudson *New York State*
FortisAlberta *Alberta*
Newfoundland Power *Newfoundland*
Maritime Electric *Prince Edward Island*
FortisOntario *Ontario*
Caribbean Utilities *Grand Cayman*
Fortis Turks and Caicos *Turks and Caicos Islands*
UNS Energy* *Arizona*

Non-Regulated

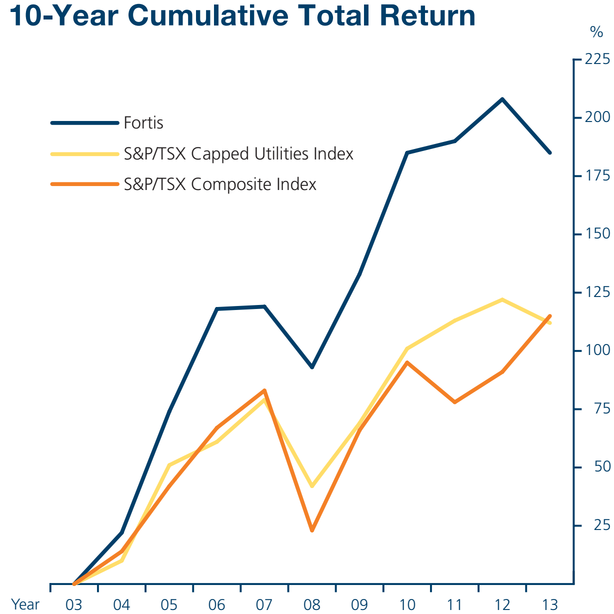
Generation ●

Locations
Belize
Ontario
British Columbia
New York State

** Pending acquisition of UNS Energy Corporation ("UNS Energy")*

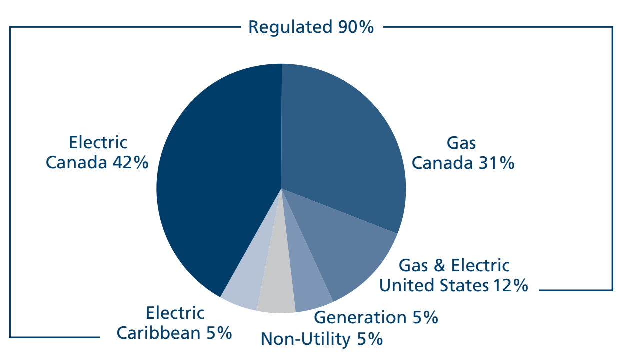
Contents

10-Year Cumulative Total Return



Total Assets $18 Billion

(as at December 31, 2013)



Investor Highlights

Regulated

Utility	Customers Gas (#)	Customers Electric (#)	Employees (#)	Peak Demand Gas (TJ)	Peak Demand Electric (MW)	Volumes Gas (PJ)	Sales Electric (GWh)	Earnings ($M)	Total Assets ($B)	2014F Midyear Rate Base ($B)	2014F Capital Program ($M)
FortisBC	956,000	164,000	2,030	1,341	699	200	3,211	177 (1)	7.5 (2)	4.9 (3)	459 (4)
Central Hudson (5)	77,000	300,000	884	125	1,202	9	2,629	23 (6)	2.3 (7)	1.1 (8)	122
FortisAlberta	–	518,000	1,106	–	2,613	–	16,934	94	3.3	2.5	413
Newfoundland Power	–	256,000	656	–	1,281	–	5,763	49	1.4	1.0	105
Maritime Electric	–	77,000	175	–	252	–	1,127	16	0.4	0.3	30
FortisOntario	–	65,000	200	–	271	–	1,278	10	0.3	0.2	26
Caribbean Utilities (9)	–	27,000	190	–	97	–	556	12	0.6	0.4	36
Fortis Turks and Caicos	–	13,000	150	–	36	–	193	11	0.3	0.2	25
Total	**1,033,000**	**1,420,000**	**5,391**	**1,466**	**6,451**	**209**	**31,691**	**392**	**16.1**	**10.6**	**1,216**

(1) *$127 million (Gas) and $50 million (Electric)*

(2) *$5.5 billion (Gas) and $2.0 billion (Electric)*

(3) *$3.7 billion (Gas) and $1.2 billion (Electric)*

(4) *$329 million (Gas) and $130 million (Electric)*

(5) *Central Hudson Gas & Electric Corporation ("Central Hudson") is the primary business of CH Energy Group, Inc., which Fortis acquired on June 27, 2013. Gas volumes, electric sales and earnings are from June 27, 2013, the date of acquisition.*

(6) *$22 million (Electric) and $1 million (Gas)*

(7) *$1.7 billion (Electric) and $0.6 billion (Gas)*

(8) *$0.9 billion (Electric) and $0.2 billion (Gas)*

(9) *Data represents 100% of Caribbean Utilities' operations except for earnings, which represent Caribbean Utilities' contribution to consolidated earnings of Fortis based on the Corporation's approximate 60% ownership interest.*

Non-Regulated

	Generating Capacity (MW)	Employees (#)	Sales Energy (GWh)	Earnings ($M)	Total Assets ($B)	2014F Capital Program ($M)
Fortis Generation (1)	103	40	386	39	0.9 (2)	131 (3)
Non-Utility (4)	–	2,775	–	18	0.9	83 (5)

(1) *Comprised of investments in Belize, Ontario, British Columbia and Upstate New York*

(2) *Includes $0.7 billion related to construction of the 335-MW Waneta Expansion hydroelectric generating facility in British Columbia*

(3) *Includes $126 million related to the Waneta Expansion hydroelectric generating facility in British Columbia*

(4) *Comprised of Fortis Properties, which includes approximately 2.7 million square feet of commercial office and retail space, primarily in Atlantic Canada, and 23 hotels across Canada, and Griffith Energy Services, Inc. ("Griffith"), which is primarily a fuel delivery business. Griffith was sold in March 2014.*

(5) *Includes $13 million for non-regulated FortisBC Alternative Energy Services Inc.*

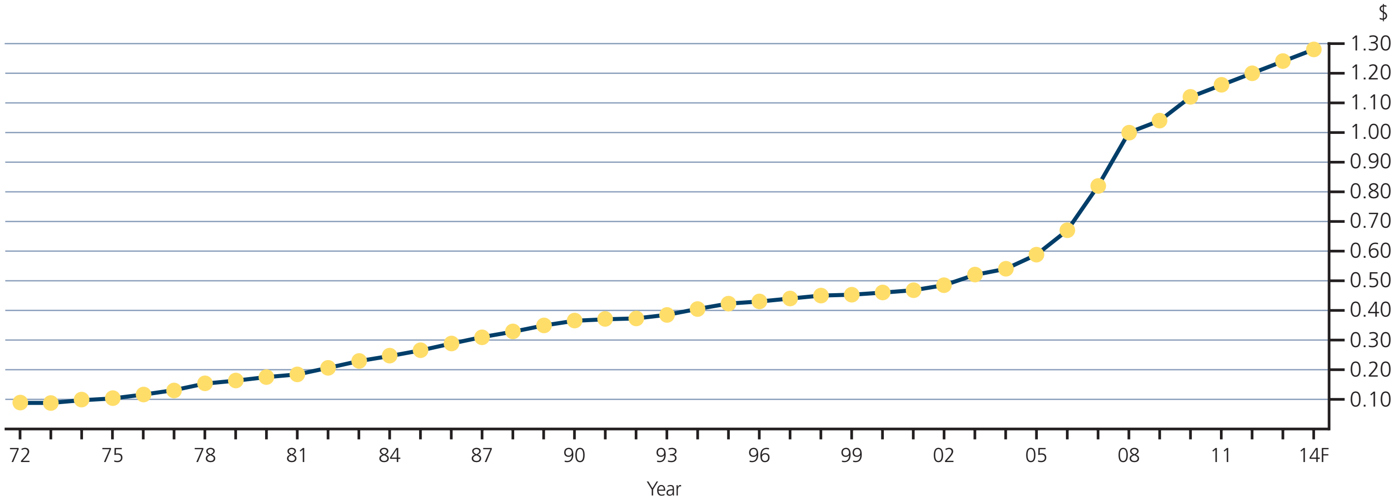
All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2013 unless otherwise indicated.

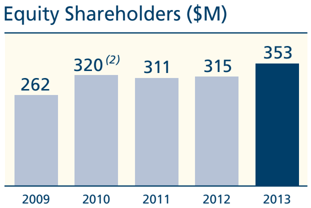
Investor Highlights [(1)]

Dividends paid per common share

Fortis has increased its annualized dividend to common shareholders for 41 consecutive years, the longest record of any public corporation in Canada.



Earnings Attributable to Common Equity Shareholders ($M)

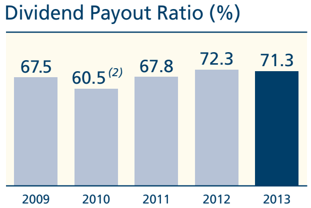


Basic Earnings per Common Share ($)

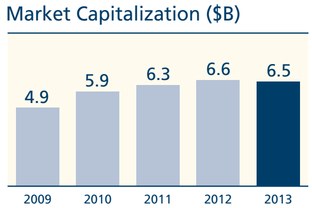
Diluted Earnings per Common Share ($)

Dividends Paid per Common Share ($)

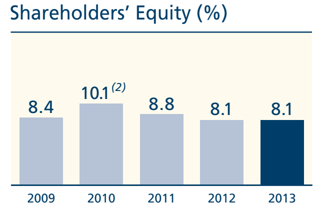
Dividend Payout Ratio (%)



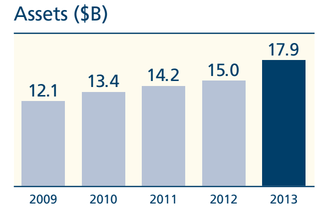
Market Capitalization ($B)



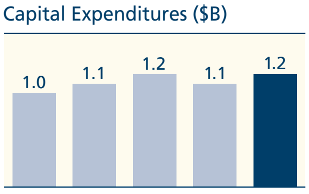
Return on Average Book Common Shareholders' Equity (%)



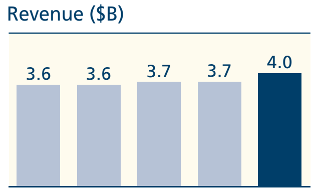
Assets ($B)



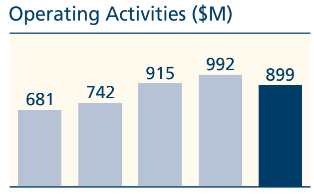
Capital Expenditures ($B)



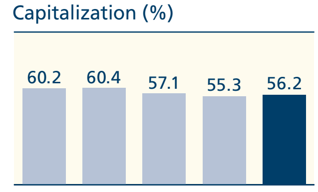
Revenue ($B)



Cash Flow from Operating Activities ($M)



Debt to Total Capitalization (%)



(1) *Financial information for the years 2010 through 2013 prepared under US generally accepted accounting principles ("GAAP"); 2009 prepared under Canadian GAAP*

(2) *Reflects the $46 million favourable impact to earnings related to the recognition of a regulatory asset associated with other post-employment benefits upon adoption of US GAAP*

All financial information is presented in Canadian dollars.

Information is for the fiscal years ended December 31.

Report to Shareholders

Dear Shareholders,

Your company achieved a considerable milestone in 2013 with the expansion into the regulated U.S. utility market. In June Fortis closed the US$1.5 billion acquisition of New York State utility CH Energy Group, Inc. ("CH Energy Group"), and in December the Corporation announced the US$4.3 billion acquisition of Arizona State utility UNS Energy Corporation ("UNS Energy"), which is expected to close later this year. These are significant regulated electricity and gas utility assets with good growth opportunities, collectively serving more than 1,000,000 customers. Increased diversification of regulated assets and earnings by geographic location and regulatory jurisdiction mitigates business risk for Fortis.


Stan Marshall
President and CEO, Fortis Inc.


David Norris
Chair of the Board, Fortis Inc.

Fortis is the largest investor-owned gas and electric distribution utility in Canada, with total assets approaching $18 billion at year-end 2013 and a midyear 2013 rate base of approximately $10.2 billion. Following the acquisition of UNS Energy, based on pro forma financial information as at December 31, 2013, total assets of Fortis will increase by approximately one-third to approach $24 billion. Regulated assets in Canada and the United States will then comprise approximately 54% and 35%, respectively, of total assets. At the time of closing the acquisition of UNS Energy, the Corporation's consolidated rate base is expected to increase by approximately US$3 billion, and Fortis utilities will serve more than 3,000,000 electricity and gas customers.

Fortis achieved net earnings attributable to common equity shareholders of $353 million in 2013, $38 million higher than earnings of $315 million for 2012. Earnings per common share were $1.74 for 2013 compared to $1.66 per common share for 2012.

Our capital program approached $1.2 billion in 2013, which marks the fifth consecutive year that capital investment has surpassed $1 billion. The $900 million, 335-megawatt Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in British Columbia, our largest capital project currently underway, is progressing well and remains on time and within budget. A total of $579 million has been invested in the project since construction began in late 2010. Fortis owns 51% of the Waneta Expansion and will operate and maintain the facility when it comes online, which is expected to be in the spring of 2015.

Your Board of Directors increased the quarterly common share dividend to 32 cents from 31 cents, commencing with the first quarter dividend paid in 2014, which translates into an annualized dividend of $1.28. Fortis has raised its annualized dividend to common shareholders for 41 consecutive years, the record for a public corporation in Canada. The dividend payout ratio was approximately 71% in 2013. Over the past 10 years, dividends have increased at a compound annual growth rate of approximately 10%. Over the same period, Fortis has delivered an average annualized total return to common shareholders of approximately 11%, outperforming the S&P/TSX Composite and S&P/TSX Capped Utilities Indices, each of which provided average annualized performance of approximately 8%. The utility sector in general was challenged in 2013, with the S&P/TSX Capped Utilities Index and Fortis realizing total returns of approximately −4% and −7%, respectively, compared to the S&P/TSX Composite Index which delivered performance of approximately 13% for the year.

The Corporation acquired CH Energy Group on June 27, 2013 for US$1.5 billion, including the assumption of US$518 million of debt on closing. Central Hudson Gas & Electric Corporation ("Central Hudson"), the main business of CH Energy Group, is a regulated transmission and distribution utility serving 377,000 electricity and gas customers in New York State's Mid-Hudson River Valley. The acquisition of CH Energy Group was primarily financed using proceeds from a $601 million common equity offering and a US$325 million unsecured notes offering.

Fortis announced in December 2013 that it agreed to acquire UNS Energy for US$60.25 per common share in cash, representing an aggregate purchase price of approximately US$4.3 billion, including the assumption of approximately US$1.8 billion of debt on closing. UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through three subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 656,000 electricity and gas customers.

The closing of the acquisition of UNS Energy, which is expected to occur by the end of 2014, is subject to receipt of UNS Energy common shareholder approval and certain regulatory and government approvals, including approval by the Arizona Corporation Commission and the U.S. Federal Energy Regulatory Commission, compliance with other applicable U.S. legislative requirements and the satisfaction of customary closing conditions.

To finance a portion of the acquisition of UNS Energy, in January 2014 Fortis completed the sale of $1.8 billion 4% convertible unsecured subordinated debentures, represented by Installment Receipts (the "Debentures"). In addition, in December 2013 the Corporation obtained a commitment from a syndicate of banks led by The Bank of Nova Scotia to provide bridge financing of $2 billion through non-revolving term credit facilities.

The acquisition of UNS Energy is consistent with our strategy of investing in high-quality regulated utility assets in Canada and the United States and is expected to be accretive to earnings per common share in the first full year after closing, excluding one-time acquisition-related costs. The acquisition of UNS Energy will further mitigate business risk for Fortis by enhancing the geographic diversification of our regulated assets, resulting in no more than one-third of total assets being located in any one regulatory jurisdiction. When we close, our regulated utilities in the United States will represent one-third of total assets, and regulated utilities and hydroelectric generation assets will comprise approximately 97% of total assets.

The Corporation's earnings for 2013 were reduced by $34 million as a result of expenses related to the CH Energy Group and UNS Energy acquisitions, compared to $7.5 million of acquisition-related expenses for 2012. Earnings for 2013 were favourably impacted by an income tax recovery of $23 million, due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends, compared to income tax expenses of $4 million associated with Part VI.1 tax for 2012. In addition, an extraordinary gain of approximately $20 million was recognized in 2013 related to the settlement of expropriation matters associated with the Exploits River Hydro Partnership ("Exploits Partnership").

Excluding the above-noted items, net earnings attributable to common equity shareholders were $344 million for 2013, up $17.5 million from earnings of $326.5 million for 2012, and earnings per common share were $1.70 for 2013 compared to $1.72 for 2012. Central Hudson contributed $23 million to earnings in 2013, while the non-regulated operations of CH Energy Group incurred a net loss of $5 million, largely associated with deferred income tax expenses related to the sale of Griffith Energy Services, Inc. ("Griffith"). In March 2014 CH Energy Group sold Griffith for approximately US$70 million plus working capital. After considering the common share offering and financing costs associated with the acquisition, earnings per common share for 2013 were not materially impacted by the acquisition of CH Energy Group.

In March 2013 FortisBC Electric acquired the electrical utility assets of the City of Kelowna (the "City") for approximately $55 million, which now allows FortisBC Electric to directly serve some 15,000 customers formerly served by the City. FortisBC Electric had provided the City with electricity under a wholesale tariff and had operated and maintained the City's electrical utility assets under contract since 2000.

Canadian Regulated Utilities contributed earnings of $346 million, $1 million higher than earnings of $345 million for 2012. Earnings at the FortisBC gas and electric utilities were reduced by approximately $15 million and $4 million, respectively, as a result of a regulatory decision related to the first stage of the Generic Cost of Capital Proceeding, which reduced the allowed rate of return on common shareholders' equity for each of the utilities and the equity component of capital structure for FortisBC Energy Inc., effective January 1, 2013. The decreases were partially offset by lower-than-expected finance charges and rate base growth, and lower operating and maintenance expenses at the FortisBC Energy companies. Earnings at FortisAlberta were $2 million lower than 2012, as a result of lower net transmission revenue and costs related to flooding in southern Alberta in June 2013, partially offset by rate base growth and growth in the number of customers. Earnings at Newfoundland Power and Maritime Electric were favourably impacted by income tax recoveries associated with Part VI.1 tax. Newfoundland Power's earnings were also favourably impacted by rate base growth and a $1 million gain on the sale of land in 2013. Earnings at FortisOntario were lower than the prior year due to the one-time impact in 2012 of the cumulative return adjustment on smart meter investments.

The regulatory calendar at our largest utilities continues to be extensive. Multi-year performance-based rate applications are progressing in British Columbia and cost of capital proceedings are continuing at FortisAlberta and FortisBC. Central Hudson will file a general rate application in mid-2014, its first such application as a Fortis utility, to establish rates effective mid-2015. Regulatory approval of the acquisition of Central Hudson included a two-year delivery-rate freeze through June 30, 2015. Over the same two-year period, Central Hudson committed to invest US$215 million in capital expenditures. In January 2014 Fortis and UNS Energy filed a joint application with the Arizona regulator seeking approval of the acquisition.

Caribbean Regulated Electric Utilities contributed earnings of $23 million, up $4 million from 2012. The increase was primarily due to the regulator-approved capitalization of overhead costs of approximately $3 million at Fortis Turks and Caicos. Electricity sales growth and an increase in base customer electricity rates at Caribbean Utilities also contributed to the higher earnings.

Non-Regulated Generation contributed earnings of $39 million, up $22 million from 2012, driven by the extraordinary gain associated with the Exploits Partnership and increased hydroelectric production in Belize.

Non-Utility operations delivered earnings of $18 million compared to $22 million for 2012. The decrease was due to the net loss of $5 million related to the sale of Griffith as noted above. Earnings at Fortis Properties were $1 million higher year over year, primarily due to improved performance at the Hospitality Division.

Corporate and Other expenses were $96 million compared to $88 million for 2012. Corporate expenses included acquisition-related expenses totalling $34 million for 2013 compared to $7.5 million for 2012. An approximate $6 million income tax recovery associated with Part VI.1 tax reduced Corporate and Other expenses in 2013 compared to income tax expense of $6 million associated with Part VI.1 tax for 2012. A foreign exchange gain of $6 million was recognized in 2013 compared to a foreign exchange loss of $2 million in 2012. Excluding the above-noted impacts, Corporate and Other expenses were $1.5 million higher year over year.

Cash flow from operating activities was $899 million, down $93 million from 2012, mainly due to unfavourable changes in working capital.

Fortis is one of the highest-rated utility holding companies in North America, with its corporate debt rated A– by Standard & Poor's ("S&P") and A(low) by DBRS, unchanged from 2012. In December 2013, after the announcement by Fortis that it had entered into an agreement to acquire UNS Energy, DBRS placed the Corporation's credit rating under review with developing implications. Similarly, S&P revised its outlook on the Corporation to negative from stable. S&P indicated that an outlook revision to stable would likely occur when the Debentures are converted to equity.

Since the beginning of 2013, Fortis has raised approximately $3.3 billion in the capital markets, which attests to investors' confidence in our business strategy. In addition to the $1.8 billion Debenture offering associated with the UNS Energy acquisition, major financing completed by Fortis included the $601 million in common equity associated with the CH Energy Group acquisition.

In July 2013 Fortis raised gross proceeds of $250 million from the issuance of 4% Fixed Rate Reset First Preference Shares, which were used to redeem all of the Corporation's 5.45% First Preference Shares for $125 million, to repay a portion of credit facility borrowings, and for other general corporate purposes. In October 2013 the Corporation closed a private placement of 10-year US$285 million unsecured notes at 3.84% and 30-year US$40 million unsecured notes at 5.08%. The proceeds were used to repay a portion of US dollar-denominated credit facility borrowings incurred to finance a portion of the CH Energy Group acquisition. In addition, the Corporation's regulated utilities issued over $300 million in long-term debt in 2013 to repay maturing debt and credit facility borrowings, to fund future capital expenditures and for general corporate purposes.

To our employees, thank you for your exemplary performance and commitment to customers. Our team will be more than 10,000 employees strong when UNS Energy joins Fortis in late 2014.

To our Board of Directors, we extend our appreciation for your governance and counsel. We also offer our gratitude and best wishes to Mr. Roy Rideout, who retired from our Board in May 2013 after 12 years of dedicated service as a Director.

Moving forward, Fortis is focused on closing the UNS Energy acquisition by the end of 2014 and on the execution of our $1.4 billion capital program in 2014. Our capital program, the majority of which is occurring in western Canada, is well underway and will ensure we continue to meet the growing energy needs of our customers. In 2014, FortisAlberta plans to invest $413 million in its electricity network; capital work associated with the Waneta Expansion in British Columbia is expected to total $126 million. FortisBC has begun expansion of its Tilbury liquefied natural gas ("LNG") facility. The expansion, subject to certain regulatory and environmental permits and approvals, at an estimated total cost of approximately $400 million, is expected to include a second LNG tank and a new liquefier, both to be in service in 2016. We are very optimistic about future opportunities for the expansion of gas infrastructure in British Columbia associated with the development of natural gas for use by the transportation sector.

Over the five years 2014 through 2018, the Corporation's capital program is expected to exceed $6.5 billion. Additionally, UNS Energy has forecast that its capital program 2015 through 2018 will be approximately $1.5 billion. The Corporation expects earnings per common share growth in 2015 and beyond as a result of contributions from the Central Hudson and UNS Energy acquisitions, and our capital program, including the completion of the Waneta Expansion in 2015 and the Tilbury LNG facility expansion in 2016, which will support continuing growth in dividends.

We are committed to continuing to grow your business profitably, while ever cognizant of our commitment to provide customers with safe, reliable, cost-effective energy service.

On behalf of the Board of Directors,

David G. Norris
Chair of the Board, Fortis Inc.

H. Stanley Marshall
President and Chief Executive Officer, Fortis Inc.

The Fortis vision is to be a leader in the North American utility industry. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

The Corporation will continue to focus on three primary objectives:

i) The growth in assets and market capitalization should be greater than the average of other North American public gas and electric utilities of similar size.
ii) Earnings growth should continue at a rate commensurate with that of a well-run North American utility.
iii) The financial and business risks of Fortis should not be substantially greater than those associated with the operation of a North American utility of similar size.

Management Discussion and Analysis

CONTENTS

Dated March 13, 2014

FORWARD-LOOKING INFORMATION

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. The MD&A should be read in conjunction with the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2013 included in the Corporation's 2013 Annual Report. Financial information for 2013 and comparative periods contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the principal business of Fortis remaining the ownership and operation of regulated electric and gas utilities; the Corporation's primary focus on Canada and the United States in the acquisition of regulated utilities; the pursuit of growth in the Corporation's non-regulated businesses in support of its regulated utility growth strategy; the expected capital investment in Canada's electricity sector over the 20-year period through 2030 to maintain system reliability; the expected timing of closing the acquisition of UNS Energy Corporation ("UNS Energy") by Fortis and the expectation that the acquisition will be accretive to earnings per common share of Fortis in the first full year after closing, excluding one-time acquisition-related expenses; the expected increase in the Corporation's rate base at the time of closing the acquisition of UNS Energy; forecast 2014 midyear rate base for the Corporation's largest regulated utilities; the Corporation's consolidated forecast gross capital expenditures for 2014 and in total over the five years 2014 through 2018; UNS Energy's forecast capital program for 2015 through 2018; the financing costs the Corporation expects to incur in 2014 associated with the convertible debentures represented by Installment Receipts (the "Debentures"); the expected net proceeds from the final installment of the Debentures; various natural gas opportunities that may be available to the Corporation; the nature, timing and amount of certain *capital projects and their expected costs and time to complete; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; the assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed; the expectation that the Corporation's regulated utilities could experience disruptions and increased costs if they are unable to maintain their asset base; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2014 capital expenditure programs; the expected consolidated long-term debt maturities and repayments in 2014 and on average annually over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to medium terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2014; the expectation that any increase in interest expense and/or fees associated with renewed and extended credit facilities will not materially impact the Corporation's consolidated financial results for 2014; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on annual basic earnings per common share; the expectation of no material adverse credit rating actions in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2014; the expectation that counterparties to derivative instruments will continue to meet their obligations; and the expectation that consolidated defined benefit net pension cost for 2014 will be comparable to that in 2013 and that there is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future.*

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; FortisAlberta's continued recovery of its cost of service and ability to earn its allowed rate of return on common shareholder's equity ("ROE") under performance-based rate-setting ("PBR"), which commenced for a five-year term effective January 1, 2013; the receipt of UNS Energy common shareholder approval and certain regulatory and government approvals required to close the acquisition of UNS Energy; the receipt of the final installment of the Debentures; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion hydroelectric generating facility; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the Government of Belize ("GOB") for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that Belize Electric Company Limited will not be expropriated by the GOB; the continuation of regulator-approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices, electricity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2018 or the adoption of International Financial Reporting Standards after 2018 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in this MD&A and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2014 include, but are not limited to: uncertainty of the impact a continuation of a low interest rate environment may have on the allowed ROE at certain of the Corporation's regulated utilities in western Canada; uncertainty regarding the treatment of certain capital expenditures at FortisAlberta under the newly implemented PBR mechanism; risks relating to the ability to close the acquisition of UNS Energy, the timing of such closing and the realization of the anticipated benefits of the acquisition; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; and the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE OVERVIEW

Fortis is the largest investor-owned gas and electric distribution utility in Canada. Its regulated utilities account for 90% of total assets and serve more than 2.4 million customers across Canada and in New York State and the Caribbean. Fortis owns non-regulated hydroelectric generation assets in Canada, Belize and Upstate New York. The Corporation's non-utility investment is comprised of hotels and commercial real estate in Canada. In 2013 the Corporation's electricity distribution systems met a combined peak demand of 6,451 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,466 terajoules.

Barry Perry, VP, Finance and CFO, Fortis Inc.

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation. Generally, under COS regulation the respective regulatory authority sets customer gas and/or electricity rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. As such, earnings of regulated utilities are generally impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and equity component of capital structure; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) timing differences within an annual financial reporting period between when actual expenses are incurred and when they are recovered from customers in rates. When forward test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

When performance-based rate-setting ("PBR") mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudent COS and earn its allowed ROE.

Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation and non-utility assets, which are treated as two separate segments. The Corporation's investments in non-regulated assets provide financial, tax and regulatory flexibility and enhance shareholder return. Income from non-regulated investments is used to help offset corporate holding company expenses, a large part of which is interest expense associated with debt incurred to finance a portion of the premiums paid on the acquisitions of regulated utilities.

The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The Corporation's interests in regulated gas and electric utilities are as follows:

Regulated Gas Utilities – Canadian

FortisBC Energy Companies: Primarily includes FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI").

FEI is the largest distributor of natural gas in British Columbia, serving approximately 850,000 customers in more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves approximately 103,000 customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler, British Columbia, which provides service to approximately 3,000 customers.

In addition to providing transmission and distribution ("T&D") services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Gas & Electric Utility – United States

Central Hudson: Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated T&D utility serving approximately 300,000 electricity customers and 77,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson was acquired by Fortis as part of the acquisition of CH Energy Group, Inc. ("CH Energy Group") in June 2013.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 518,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 164,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"), and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT. In March 2013 FortisBC Inc. acquired the City of Kelowna's electrical utility assets.

c. *Newfoundland Power:* Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 256,000 customers. The Company has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Comprised of Maritime Electric and FortisOntario. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving approximately 77,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers.

Regulated Electric Utilities – Caribbean

a. *Caribbean Utilities:* Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 27,000 customers. The Company has an installed diesel-powered generating capacity of 150 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2012 – 60%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U).

b. *Fortis Turks and Caicos:* Comprised of FortisTCI Limited ("FortisTCI") and Turks and Caicos Utilities Limited ("TCU"), which was acquired in August 2012 (collectively "Fortis Turks and Caicos"). Both of the Fortis Turks and Caicos utilities are integrated electric utilities serving approximately 13,000 customers and, combined, have a diesel-powered generating capacity of 76 MW. Fortis Turks and Caicos provides electricity to Providenciales, North Caicos, Middle Caicos and South Caicos through FortisTCI, and to Grand Turk and Salt Cay through TCU.

Non-Regulated – Fortis Generation

The following summary describes the Corporation's non-regulated generation assets by location:

a. *Belize:* Comprised of the 25-MW Mollejon, 7-MW Chalillo and 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

b. *Ontario:* Comprised of six small hydroelectric generating facilities in eastern Ontario, with a combined capacity of 8 MW, and a 5-MW gas-powered cogeneration plant in Cornwall.

c. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia, which sells its entire output to BC Hydro. The contract with BC Hydro expired in 2013 and is subject to termination by BC Hydro with five months' notice. Non-regulated generation operations in British Columbia also include the Corporation's 51% controlling ownership interest in the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The Waneta Partnership commenced construction of the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, in late 2010. The Waneta Expansion is expected to come into service in spring 2015. The output of the Waneta Expansion will be sold to BC Hydro and FortisBC Electric under 40-year contracts.

d. *Upstate New York:* Comprised of four hydroelectric generating facilities, with a combined capacity of approximately 23 MW, in Upstate New York, operating under licences from the U.S. Federal Energy Regulatory Commission ("FERC"). Hydroelectric generation operations in Upstate New York are conducted through the Corporation's indirectly wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Non-Utility

a. *Fortis Properties:* Fortis Properties owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces, and owns and operates approximately 2.7 million square feet of commercial office and retail space, primarily in Atlantic Canada.

b. *Griffith:* Comprised primarily of Griffith Energy Services, Inc. ("Griffith"), which supplies petroleum products and related services to approximately 60,000 customers in the Mid-Atlantic Region of the United States. Griffith was acquired by Fortis as part of the acquisition of CH Energy Group and was sold in March 2014. As at December 31, 2013, Griffith has been classified as held for sale. For further information on the sale of Griffith, refer to the "Significant Items – Sale of Griffith" section of this MD&A.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment, and those business operations that are below the required threshold for reporting as separate segments.

The Corporate and Other segment includes finance charges, comprised of interest on debt incurred directly by Fortis and FortisBC Holdings Inc. ("FHI"); dividends on preference shares; other corporate expenses, including Fortis and FHI corporate operating costs, net of recoveries from subsidiaries; acquisition-related expenses; interest and miscellaneous revenue; and related income taxes.

Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

CORPORATE VISION AND STRATEGY

The principal business of Fortis is and will remain the ownership and operation of regulated gas and electric utilities, with a vision to be a leader in the North American utility industry. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders. The key goals of the Corporation's regulated utilities are to operate sound electricity and gas distribution systems; deliver safe, reliable, cost-efficient energy to customers; and conduct business in an environmentally responsible manner.

Fortis has adopted a strategy of profitable growth with earnings per common share and total shareholder return as the primary measures of performance. Over the 10-year period ended December 31, 2013, earnings per common share of Fortis grew at a compound annual growth rate of 5.1%. Over the past 10 years, Fortis delivered an average annualized total return to shareholders of approximately 11%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, each of which delivered average annualized performance of approximately 8% over the same period.

The Corporation's first priority remains the continued profitable expansion of existing operations. Fortis has also demonstrated its ability to acquire additional regulated utilities in Canada and the United States. In recent years, the primary focus has been utilities in the United States because there are limited opportunities available in Canada to acquire additional regulated electric and gas utilities. The U.S. marketplace provides significantly more acquisition targets.

The acquisition of Central Hudson in June 2013 represents the Corporation's initial entry into the regulated U.S. utility market. This U.S. regulated utility investment is expected to be further enhanced through the Corporation's acquisition of UNS Energy Corporation ("UNS Energy"). The pending acquisition will further mitigate business risk for Fortis by enhancing the geographic diversification of the Corporation's regulated assets, resulting in no more than one-third of total assets being located in any one regulatory jurisdiction.

For further information on the pending acquisition of UNS Energy, refer to the "Key Trends, Risks and Opportunities – The Regulated U.S. Utility Market", "Significant Items – Pending Acquisition of UNS Energy" and "Business Risk Management – Completion of the Acquisition of UNS Energy" sections of this MD&A.

Fortis has built a base of non-regulated and international investments that provide financial, tax and regulatory flexibility. Fortis will pursue opportunities to continue to grow its non-regulated hydroelectric and non-utility assets in support of its utility growth strategy. Once completed in spring 2015, the Waneta Expansion is expected to more than double annual earnings from the Non-Regulated – Fortis Generation segment from the expected 2014 earnings level.

KEY TRENDS, RISKS AND OPPORTUNITIES

General Trends for the Energy Sector: Traditional goals of safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of key issues impacting the energy industry. Evolving and more global issues include climate change, national issues pertaining to security, the development of expanded natural gas resources as a source of energy supply, the increasing deployment of alternative energy resources, as well as a growing desire by customers to have greater control over their energy use to lower costs and decrease their environmental footprint.

According to the National Energy Board energy market assessment report, *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*, Canada has ample energy resources to meet its growing energy needs. Over the next 20 years, energy production levels are expected to exceed domestic requirements, resulting in growing amounts of energy available for export. Total Canadian energy production is expected to grow substantially through 2035, with oil and natural gas production projected to increase by 75% and 25%, respectively. Canadian total electricity generation and supply are projected to increase over the same period, with natural gas-powered generation capacity projected to increase substantially, largely at the expense of coal-powered capacity.

Industry reports project that, over the 20-year period through 2030, Canada will need to invest $350 billion in its electricity infrastructure in order to maintain system reliability. Approximately two-thirds of the investment will be to replace or renew aging generation assets, add to renewable generation capability and accommodate market growth. The remainder will be for transmission, expanding distribution and maintaining service quality.

As noted in the 2013 U.S. edition of the ExxonMobil report *The Outlook for Energy: A View to 2040*, global demand for energy is expected to rise by about 35% from 2010 to 2040, requiring trillions of dollars of investment in infrastructure and technology. North American oil and natural gas production is forecast to rise by about 45% from 2010 to 2040, boosted by activity in the United States. As a result of ongoing efficiency improvements, the United States also continues to reduce its energy consumption. Shale gas and other unconventional supplies from North America will play an increasingly important role in meeting global demand for natural gas. North America, which in 2010 imported 15% of its total energy and 35% of its oil, is likely to transition into a net energy exporter by about 2025.

The Regulated U.S. Utility Market: The acquisition of Central Hudson in June 2013 represents the Corporation's initial entry into the regulated U.S. utility market and has established a platform for Fortis to build its U.S. regulated electric and gas utility assets. In December 2013 Fortis entered into an agreement and plan of merger to acquire UNS Energy. UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through three subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 656,000 electricity and gas customers. Fortis is focused on closing the UNS Energy acquisition by the end of 2014. These acquisitions demonstrate the execution of the Corporation's strategy of investing in high-quality regulated utility assets in the United States.

The pending acquisition of UNS Energy is attractive for the following reasons: (i) the acquisition is expected to be accretive to earnings per common share of Fortis in the first full year after closing, excluding one-time acquisition-related costs; (ii) UNS Energy operates a well-run electric and gas system, serving a diversified, primarily residential and commercial, customer base; (iii) the acquisition increases the diversification of the Corporation's regulated assets and earnings by geographic location and regulatory jurisdiction; (iv) UNS Energy is a single-state utility that operates within a supportive regulatory environment; (v) favourable local economic conditions support growth; (vi) UNS Energy's continued investment in its electric and gas businesses to provide safe, reliable and cost-effective energy service to its customers is expected to result in attractive rate base growth; (vii) UNS Energy expects to invest significant capital into diversifying its generation fleet, including the purchase of the natural gas-powered combined-cycle Gila River Unit 3 generation plant and utility scale renewables generation; and (viii) UNS Energy has an experienced management team committed to providing customers with safe, reliable, cost-effective energy service.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's utilities is regulated by the regulatory body in its respective operating jurisdiction. In total the Corporation's utilities operate in eight regulatory jurisdictions. Relationships with the regulatory authorities are managed at the local utility level.

Commitment by the Corporation's utilities to provide safe and reliable service, customer satisfaction and operational excellence and to promote positive customer and regulatory relations is important for supportive regulatory relationships and obtaining full cost recovery and competitive returns for the Corporation's shareholders.

For a further discussion of regulatory risk and the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Business Risk Management – Regulatory Risk" and "Regulatory Highlights" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth: The Corporation's regulated midyear rate base for 2013 was approximately $10 billion. At the time of closing the acquisition of UNS Energy, the Corporation's rate base is expected to increase by approximately US$3 billion. Over the five years 2014 through 2018, the Corporation's consolidated capital expenditure program is expected to exceed $6.5 billion. Additionally, UNS Energy has forecast that its capital program for 2015 through 2018 will be approximately $1.5 billion (US$1.4 billion). Fortis expects that investment in its utilities associated with their capital expenditure programs will support continuing growth in earnings and dividends.

For further information on the Corporation's consolidated capital expenditure program and rate base of its largest regulated utilities, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Natural Gas Opportunities: The outlook for the energy sector in British Columbia is positive with the development of the Province's natural gas resources in support of liquefied natural gas ("LNG") export opportunities.

The new regulation under the *Clean Energy Act* recently passed in British Columbia will enable FortisBC to advance the use of natural gas in the transportation sector, given the opportunity it provides to reduce greenhouse gas ("GHG") emissions. The economic benefits of using natural gas for transportation applications include cost savings for customers, contributions to the provincial economy through increased tax revenues and reduced costs for public services, schools and public transit as the result of fuel-cost savings.

In November 2013 the Government of British Columbia announced the exemption of FEI's Tilbury LNG facility expansion from normal course regulatory review and imposed an upper limit of $400 million of project costs associated with the expansion. FEI has begun the expansion, which will increase LNG production and storage capabilities, and it is expected to be in service in 2016.

Traditionally, the majority of natural gas production in northern British Columbia has served the provincial and Pacific Northwest markets via the Westcoast (Spectra) system. However, to realize the full potential of British Columbia shale gas plays, additional capacity to connect to markets will have to be developed. FortisBC is exploring pipeline investment opportunities that include expansion of its existing distribution system to supply natural gas to a prospective LNG export facility, as well as to expand capacity on its Southern Crossing transmission pipeline.

The combination of an abundant supply of natural gas, improved economics and more positive government policy may allow the creation of industrial developments that rely on the use of natural gas to emerge on the coast of British Columbia in the medium to long term. Natural gas is positioned to enter into new markets, such as the transportation sector, with both compressed natural gas ("CNG") and LNG. Low costs for natural gas and a strong supply outlook are generating new interest for large industrial customers and niche LNG producers to utilize the FortisBC gas system. Opportunities may also exist for gas-powered electricity generation.

Western Canadian Economies: A large proportion of the businesses of Fortis serve the economies of western Canada, where economic growth has generally been higher than the rest of the country. As at December 31, 2013, regulated utility assets comprised 90% of total assets (December 31, 2012 – 90%) and regulated utility assets in western Canada comprised 67% of total regulated assets (December 31, 2012 – 78%). FortisAlberta is the Corporation's fastest-growing utility. Since it was acquired in 2004, the rate base of FortisAlberta has grown by approximately 275% and now totals approximately $2.3 billion. FortisAlberta services some of the fastest-growing areas of Canada, with much of the utility's growth related to oil sands and shale oil developments and associated residential and commercial developments, predominantly in the communities surrounding the cities of Calgary and Edmonton.

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities issue debt at terms ranging between 10 and 50 years. As at December 31, 2013, approximately 80% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated long-term debt maturities and repayments to be $780 million in 2014 and to average approximately $335 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $2.7 billion in credit facilities, of which approximately $2.2 billion was unused as at December 31, 2013. In January 2014, as a result of closing the $1.8 billion convertible debentures related to the pending acquisition of UNS Energy, Fortis agreed to maintain availability under its $1 billion committed revolving corporate credit facility of not less than $600 million to cover the principal amount of the first installment of the convertible debentures in the event of a mandatory redemption. For further information, refer to the "Significant Items – Convertible Debentures Represented by Installment Receipts" section of this MD&A. Based on current credit ratings and conservative capital structures, the Corporation and its regulated utilities expect to continue to have reasonable access to long-term capital in 2014.

Dividend Increases: Dividends paid per common share increased to $1.24 in 2013. Fortis increased its quarterly common share dividend to 32 cents, commencing with the first quarter dividend paid in 2014. The 3.2% increase in the quarterly common share dividend translates into an annualized dividend of $1.28 for 2014 and extends the Corporation's record of annual common share dividend increases to 41 consecutive years, the longest record of any public corporation in Canada.

Expropriated Assets: The GOB expropriated the Corporation's common share ownership in Belize Electricity in June 2011. The Corporation is challenging the constitutionality of the expropriation in the Belize Courts. Although the GOB initiated contact with Fortis, there has been no settlement on the fair value compensation owing to Fortis as a result of the expropriation. As at December 31, 2013, the book value of the Corporation's expropriated investment in Belize Electricity is $108 million, including foreign exchange impacts. For further information, refer to the "Business Risk Management – Expropriation of Shares in Belize Electricity" section of this MD&A.

SIGNIFICANT ITEMS

Pending Acquisition of UNS Energy: In December 2013 Fortis entered into an agreement and plan of merger to acquire UNS Energy (NYSE:UNS) for US$60.25 per common share in cash, representing an aggregate purchase price of approximately US$4.3 billion, including the assumption of approximately US$1.8 billion of debt on closing. UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through three subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 656,000 electricity and gas customers.

The closing of the acquisition, which is expected to occur by the end of 2014, is subject to receipt of UNS Energy common shareholder approval and certain regulatory and government approvals, including approval by the Arizona Corporation Commission ("ACC") and FERC, and compliance with other applicable U.S. legislative requirements and the satisfaction of customary closing conditions. In January 2014 Fortis and UNS Energy filed a joint application with the ACC seeking approval of the acquisition. The FERC application was filed in February 2014. UNS Energy mailed proxy materials to its shareholders and expects the shareholder vote on the transaction to occur on March 26, 2014.

The pending acquisition is consistent with the Corporation's strategy of investing in high-quality regulated utility assets in Canada and the United States and is expected to be accretive to earnings per common share of Fortis in the first full year after closing, excluding one-time acquisition-related costs. At the time of closing the acquisition, the Corporation's consolidated rate base is expected to increase by approximately US$3 billion. The acquisition of UNS Energy will further mitigate business risk for Fortis by enhancing the geographic diversification of the Corporation's regulated assets, resulting in no more than one-third of total assets being located in any one regulatory jurisdiction.

For the purpose of financing the acquisition, in December 2013 the Corporation obtained a commitment letter from a syndicate of banks led by The Bank of Nova Scotia to provide an aggregate of $2 billion non-revolving term credit facilities, consisting of a $1.7 billion short-term bridge facility, repayable in full nine months following its advance, and a $300 million medium-term bridge facility, repayable in full on the second anniversary of its advance.

Convertible Debentures Represented by Installment Receipts: To finance a portion of the pending acquisition of UNS Energy, in January 2014 Fortis, through a direct wholly owned subsidiary, completed the sale of $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures, represented by Installment Receipts (the "Debentures").

The offering of the Debentures consisted of a bought deal placement of $1.594 billion aggregate principal amount of Debentures underwritten by a syndicate of underwriters (the "Public Offering") and the sale of $206 million aggregate principal amount of Debentures to certain institutional investors on a private placement basis (together with the Public Offering, the "Offerings"). The overallotment option in connection with the Public Offering was not exercised.

The Debentures were sold on an installment basis at a price of $1,000 per Debenture, of which $333 was paid on closing of the Offerings and the remaining $667 is payable on a date ("Final Installment Date") to be fixed following satisfaction of all conditions precedent to the closing of the acquisition of UNS Energy. Prior to the Final Installment Date, the Debentures are represented by Installment Receipts. The Installment Receipts began trading on the TSX on January 9, 2014 under the symbol "FTS.IR". The Debentures will not be listed. The Debentures will mature on January 9, 2024 and bear interest at an annual rate of 4% per $1,000 principal amount of Debentures until and including the Final Installment Date, after which the interest rate will be 0%.

If the Final Installment Date occurs prior to the first anniversary of the closing of the Offerings, holders of Debentures who have paid the final installment will be entitled to receive, in addition to the payment of accrued and unpaid interest, an amount equal to the interest that would have accrued from the day following the Final Installment Date to, but excluding, the first anniversary of the closing of the Offerings had the Debentures remained outstanding until such date. As a result, in 2014 the Corporation expects to incur approximately $72 million ($51 million after tax) in financing costs associated with the Debentures.

At the option of the investors and provided that payment of the final installment has been made, each Debenture will be convertible into common shares of Fortis at any time after the Final Installment Date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per common share, being a conversion rate of 32.5521 common shares per $1,000 principal amount of Debentures.

The Debentures will not be redeemable except that Fortis will redeem the Debentures at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions necessary to approve the acquisition of UNS Energy will not be satisfied; (ii) termination of the acquisition agreement; and (iii) July 2, 2015, if notice of the Final Installment Date has not been given to investors on or before June 30, 2015. In addition, after the Final Installment Date, any Debentures not converted may be redeemed by Fortis at a price equal to their principal amount plus unpaid interest accrued prior to the Final Installment Date. Under the terms of the Installment Receipt Agreement, Fortis agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Installment Date has occurred, the Corporation will at all times maintain availability under its committed revolving corporate credit facility of not less than $600 million to cover the principal amount of the first installment of the Debentures in the event of a mandatory redemption.

At maturity, Fortis will have the right to pay the principal amount due in common shares, which will be valued at 95% of the weighted-average trading price on the TSX for the 20 consecutive trading days ending five trading days preceding the maturity date.

The net proceeds of the first installment of the Offerings was approximately $563 million. A significant portion of the net proceeds is cash on hand, while a portion was used to repay borrowings under the Corporation's existing revolving credit facility and for other general corporate purposes. The net proceeds of the final installment payment of the Offerings are expected to be, in aggregate, approximately $1.165 billion.

Acquisition of CH Energy Group: On June 27, 2013, Fortis acquired all of the outstanding common shares of CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of US$518 million of debt on closing. The net purchase price of approximately $1,019 million (US$972 million) was financed through proceeds from the issuance of 18.5 million common shares of Fortis pursuant to the conversion of Subscription Receipts on closing of the acquisition for proceeds of approximately $567 million, net of after-tax expenses, and a US$325 million unsecured notes offering, with the balance being funded through drawings under the Corporation's $1 billion committed credit facility.

CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson, is a regulated T&D utility, which accounts for approximately 93% of the total assets of CH Energy Group and is subject to regulation by the New York State Public Service Commission ("PSC") under a traditional COS model. CH Energy Group's non-regulated operations primarily consist of Griffith, which mainly supplies petroleum products and related services to approximately 60,000 customers in the Mid-Atlantic Region of the United States.

Sale of Griffith: In March 2014 CH Energy Group sold its non-regulated subsidiary, Griffith, for approximately US$70 million plus working capital. As a result, the assets and liabilities of Griffith have been classified as held for sale on the consolidated balance sheet as at December 31, 2013 and the results of operations have been presented as discontinued operations on the consolidated statement of earnings.

Part VI.1 Tax: In June 2013 the Government of Canada enacted previously announced legislative changes associated with Part VI.1 tax on the Corporation's preference share dividends. In accordance with US GAAP, income taxes are required to be recognized based on enacted tax legislation. In 2013 the Corporation recognized an approximate $23 million income tax recovery due to the enactment of higher deductions associated with Part VI.1 tax. The income tax recovery impacted earnings at Newfoundland Power, Maritime Electric and the Corporation as a result of the allocation of Part VI.1 tax in previous years.

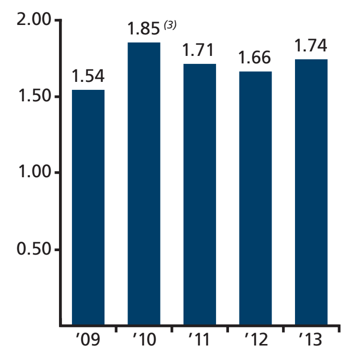
Settlement of Expropriation Matters – Exploits River Hydro Partnership: In March 2013 the Corporation and the Government of Newfoundland and Labrador settled all matters, including release from all debt obligations, pertaining to the Government's December 2008 expropriation of non-regulated hydroelectric generating assets and water rights in central Newfoundland, then owned by the Exploits River Hydro Partnership ("Exploits Partnership"), in which Fortis held an indirect 51% interest. As a result of the settlement, an extraordinary after-tax gain of approximately $20 million was recognized in 2013.

Acquisition of the Electrical Utility Assets from the City of Kelowna: FortisBC Electric acquired the electrical utility assets of the City of Kelowna (the "City") for approximately $55 million in March 2013, which now allows FortisBC Electric to directly serve some 15,000 customers formerly served by the City. FortisBC Electric had provided the City with electricity under a wholesale tariff and had operated and maintained the City's electrical utility assets under contract since 2000.

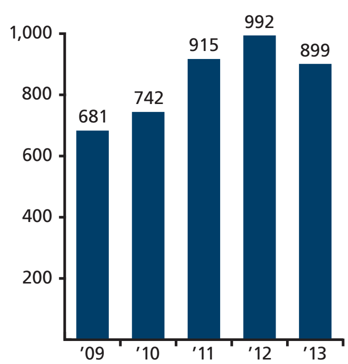
SUMMARY FINANCIAL HIGHLIGHTS

For the Years Ended December 31	**2013**	2012	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**353**	315	38
Basic Earnings per Common Share *($)*	**1.74**	1.66	0.08
Diluted Earnings per Common Share *($)*	**1.73**	1.65	0.08
Weighted Average Number of Common Shares Outstanding *(millions)*	**202.5**	190.0	12.5
Cash Flow from Operating Activities *($ millions)*	**899**	992	(93)
Dividends Paid per Common Share *($)*	**1.24**	1.20	0.04
Dividend Payout Ratio *(%)*	**71.3**	72.3	(1.0)
Return on Average Book Common Shareholders' Equity *(%)* [(1)]	**8.1**	8.1	–
Total Assets *($ billions)*	**17.9**	15.0	2.9
Gross Capital Expenditures *($ millions)*	**1,175**	1,146	29
Public Common Share Offering *($ millions)*	**601**	–	601
Public Preference Share Offerings *($ millions)*	**250**	200	50
Long-Term Debt Offerings *($ millions)*	**657**	125	532

Basic Earnings per Common Share *($)* [(2)]



Cash Flow from Operating Activities *($ millions)* [(2)]



Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $353 million in 2013, $38 million higher than earnings of $315 million for 2012. Earnings for 2013 were reduced by $34 million as a result of expenses related to the CH Energy Group and UNS Energy acquisitions, compared to $7.5 million of acquisition-related expenses for 2012. Earnings for 2013 were favourably impacted by an income tax recovery of $23 million, due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends, compared to income tax expenses of $4 million associated with Part VI.1 tax for 2012. In addition, an extraordinary gain of approximately $20 million was recognized in 2013 related to the settlement of expropriation matters associated with the Exploits Partnership.

Excluding the above-noted items, net earnings attributable to common equity shareholders were $344 million for 2013, up $17.5 million from earnings of $326.5 million for 2012. Central Hudson contributed $23 million to earnings in 2013, while the non-regulated operations of CH Energy Group incurred a net loss of $5 million, largely associated with deferred income tax expenses related to the sale of Griffith.

Earnings at Canadian Regulated Gas and Electric Utilities were up $1 million from 2012. Earnings at the FortisBC Energy companies and FortisBC Electric were reduced by approximately $15 million and $4 million, respectively, as a result of a regulatory decision related to the first stage of the Generic Cost of Capital ("GCOC") Proceeding, which reduced the ROE for each of the utilities and the equity component of capital structure for FEI, effective January 1, 2013. The decreases were partially offset by lower-than-expected finance charges and rate base growth, and lower operating and maintenance expenses at the FortisBC Energy companies. Earnings at FortisAlberta were $2 million lower than in 2012, as a result of lower net transmission revenue and costs related to flooding in southern Alberta in June 2013, partially offset by rate base growth and growth in the number of customers. Earnings at Newfoundland Power and Maritime Electric were favourably impacted by income tax recoveries associated with Part VI.1 tax. Newfoundland Power's earnings were also favourably impacted by rate base growth and a $1 million gain on the sale of land in 2013. Earnings at FortisOntario decreased due to the impact of the cumulative return adjustment on smart meter investments in 2012.

Caribbean Regulated Electric Utilities delivered earnings $4 million higher than in 2012. The increase was primarily due to the regulator-approved capitalization of overhead costs at Fortis Turks and Caicos.

(1) Return on average book common shareholders' equity is a non-US GAAP measure and is defined as net earnings attributable to common equity shareholders divided by the average of opening and closing consolidated shareholders' equity, excluding preference shares and non-controlling interests. Return on average book common shareholders' equity is referred to by users of the Corporation's consolidated financial statements in evaluating the results of operations.

(2) Years 2010 through 2013 prepared in accordance with US GAAP. 2009 prepared in accordance with Canadian generally accepted accounting principles.

(3) Reflects the $46 million favourable impact to earnings related to the recognition of a regulatory asset associated with other post-employment benefits upon adoption of US GAAP

Earnings at Non-Regulated Fortis Generation were up $22 million from 2012, driven by the extraordinary gain associated with the Exploits Partnership and increased hydroelectric production in Belize.

Corporate and Other expenses were up $8 million from 2012. Higher acquisition-related expenses were partially offset by an income tax recovery associated with Part VI.1 tax, the release of income tax provisions and a foreign exchange gain in 2013, compared to a foreign exchange loss in 2012.

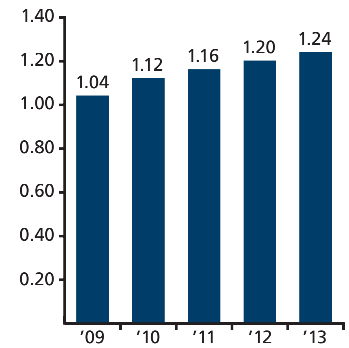
Basic Earnings per Common Share: Basic earnings per common share were $1.74 in 2013 compared to $1.66 in 2012. The increase was due to higher net earnings attributable to common equity shareholders, partially offset by the impact of a 6.6% increase in the weighted average number of common shares outstanding, largely due to the issuance of 18.5 million common shares pursuant to the conversion of Subscription Receipts on closing of the acquisition of CH Energy Group in June 2013.

Cash Flow from Operating Activities: Cash flow from operating activities was $899 million for 2013, down $93 million from $992 million for 2012. The decrease was primarily due to unfavourable changes in working capital and long-term regulatory deferral accounts at FortisAlberta.

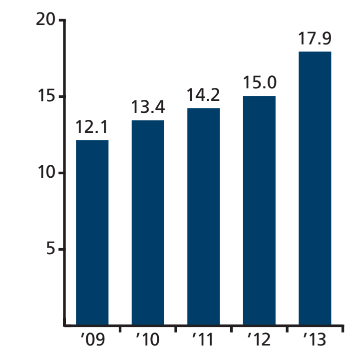
Dividends: Dividends paid per common share increased to $1.24 in 2013, up 3.3% from $1.20 in 2012. Fortis increased its quarterly common share dividend to 32 cents from 31 cents, commencing with the first quarter dividend paid on March 1, 2014. The Corporation's dividend payout ratio was 71.3% in 2013 compared to 72.3% in 2012.

Total Assets: Total assets increased 19.3% to approximately $17.9 billion at the end of 2013 compared to approximately $15.0 billion at the end of 2012. The increase reflects the Corporation's acquisition of CH Energy Group in June 2013 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities in western Canada, and the continued construction of the Waneta Expansion.

Dividends Paid per Common Share *($)*



Total Assets *($ billions)*
(as at December 31) [(1)]



Gross Capital Expenditures: Consolidated capital expenditures, before customer contributions, were $1,175 million in 2013 compared to $1,146 million in 2012. Capital investment at the regulated utilities in western Canada totalled $713 million, representing approximately 61% of gross capital expenditures. Capital investment was driven by customer growth and the ongoing need to enhance the reliability and efficiency of energy systems. Construction of the $900 million, 335-MW Waneta Expansion is progressing well and remains on time and within budget, with completion of the facility expected in spring 2015. Approximately $143 million was spent on the Waneta Expansion in 2013, for a total of approximately $579 million since construction began late in 2010. For a further discussion of the Corporation's consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Long-Term Capital: In June 2013 the Corporation issued 18.5 million common shares, pursuant to the conversion of Subscription Receipts on closing of the acquisition of CH Energy Group, for proceeds of approximately $567 million, net of after-tax expenses. In July 2013 Fortis issued 10 million 4% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series K for gross proceeds of $250 million and used a portion of the proceeds to redeem all of the Corporation's 5.45% First Preference Shares, Series C in July 2013 for $125 million. In 2013 long-term debt offerings were completed at each of the Corporation, FortisAlberta, Newfoundland Power, Central Hudson and Caribbean Utilities. For further information, refer to the "Liquidity and Capital Resources – Summary of Consolidated Cash Flows" section of this MD&A.

[(1)] Years 2010 through 2013 prepared in accordance with US GAAP. 2009 prepared in accordance with Canadian generally accepted accounting principles.

CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31

($ millions)	**2013**	2012	Variance
Revenue	**4,047**	3,654	393
Energy Supply Costs	**1,617**	1,522	95
Operating Expenses	**1,037**	868	169
Depreciation and Amortization	**541**	470	71
Other Income (Expenses), Net	**(31)**	4	(35)
Finance Charges	**389**	366	23
Income Tax Expense	**32**	61	(29)
Earnings From Continuing Operations	**400**	371	29
Earnings From Discontinued Operations, Net of Tax	**–**	–	–
Earnings Before Extraordinary Item	**400**	371	29
Extraordinary Gain, Net of Tax	**20**	–	20
Net Earnings	**420**	371	49
Net Earnings Attributable to:			
Non-Controlling Interests	**10**	9	1
Preference Equity Shareholders	**57**	47	10
Common Equity Shareholders	**353**	315	38
Net Earnings	**420**	371	49

Revenue

The increase in revenue was driven by the acquisition of CH Energy Group, an increase in the base component of rates at most of the regulated utilities, higher electricity sales and gas volumes, and favourable foreign exchange associated with the translation of US dollar-denominated revenue.

The increase was partially offset by decreases in the allowed ROEs at the FortisBC Energy companies and FortisBC Electric, and a decrease in the equity component of capital structure at FEI, effective January 1, 2013, as a result of the regulatory decision on the first stage of the GCOC Proceeding in British Columbia, lower net transmission revenue at FortisAlberta and a decrease in the cost of natural gas charged to customers at the FortisBC Energy companies.

Energy Supply Costs

The increase in energy supply costs was primarily due to the acquisition of CH Energy Group and higher electricity sales and gas volumes, which increased fuel, power and natural gas purchases. The increase was partially offset by a lower cost of natural gas at the FortisBC Energy companies.

Operating Expenses

The increase in operating expenses was primarily due to the acquisition of CH Energy Group and general inflationary and employee-related cost increases at most of the Corporation's regulated utilities.

Depreciation and Amortization

The increase in depreciation and amortization was due to continued investment in energy infrastructure at the Corporation's regulated utilities and the acquisition of CH Energy Group.

Other Income (Expenses), Net

The increase in other expenses was primarily due to approximately $41 million (US$40 million), or $26 million (US$26 million) after tax, of expenses associated with customer and community benefits offered by the Corporation to close the acquisition of CH Energy Group, and expenses of $3 million ($2 million after tax) related to the pending acquisition of UNS Energy. The increase was partially offset by a foreign exchange gain of $6 million for 2013 compared to a foreign exchange loss of $2 million for 2012.

Finance Charges

The increase in finance charges was primarily due to the acquisition of CH Energy Group, including interest associated with financing the acquisition, and higher long-term debt levels in support of the utilities' capital expenditure programs. The increase was partially offset by higher capitalized interest associated with the financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion.

Income Tax Expense

Income tax expense decreased primarily due to an income tax recovery of $23 million, due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends, compared to income tax expenses of $4 million associated with Part VI.1 tax in 2012, and the release of income tax provisions of $7 million in 2013 compared to $4 million in 2012. The decrease was partially offset by the acquisition of CH Energy Group, higher income taxes at the FortisBC Energy companies and FortisBC Electric, and deferred income tax expenses associated with the sale of Griffith.

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

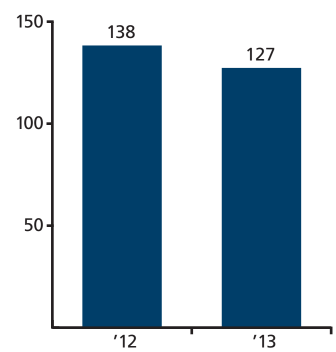
Years Ended December 31 *($ millions)*	2013	2012	Variance
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies	**127**	138	(11)
Regulated Gas & Electric Utility – United States			
Central Hudson	**23**	–	23
Regulated Electric Utilities – Canadian			
FortisAlberta	**94**	96	(2)
FortisBC Electric	**50**	50	–
Newfoundland Power	**49**	37	12
Other Canadian Electric Utilities	**26**	24	2
	219	207	12
Regulated Electric Utilities – Caribbean	**23**	19	4
Non-Regulated – Fortis Generation	**39**	17	22
Non-Regulated – Non-Utility	**18**	22	(4)
Corporate and Other	**(96)**	(88)	(8)
Net Earnings Attributable to Common Equity Shareholders	**353**	315	38

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities is provided in the "Regulatory Highlights" section of this MD&A.

REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2013 regulated earnings represented approximately 87% (2012 – 90%) of the Corporation's earnings from its operating segments (excluding Corporate and Other segment expenses). Total regulated assets represented 90% of the Corporation's total assets as at December 31, 2013 (December 31, 2012 – 90%).

Regulated Gas Utilities – Canadian Earnings *($ millions)*



Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2013 were $127 million (2012 – $138 million), which represented approximately 32% of the Corporation's total regulated earnings (2012 – 38%). Regulated Gas Utilities – Canadian assets were approximately $5.5 billion as at December 31, 2013 (December 31, 2012 – $5.5 billion), which represented approximately 34% of the Corporation's total regulated assets as at December 31, 2013 (December 31, 2012 – 41%).

FortisBC Energy Companies

Financial Highlights

Years Ended December 31	2013	2012	Variance
Gas Volumes *(petajoules ("PJ"))*	**200**	199	1
Revenue *($ millions)*	**1,378**	1,426	(48)
Earnings *($ millions)*	**127**	138	(11)

Gas Volumes

The increase in gas volumes was due to higher average consumption by residential customers due to colder weather in the winter months, partially offset by lower gas transportation volumes, mainly due to certain transportation customers switching from natural gas to alternative fuel sources.

As at December 31, 2013, the total number of customers served by the FortisBC Energy companies was approximately 956,000, up 11,000 customers from December 31, 2012.

The FortisBC Energy companies earn approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulator-approved deferral mechanisms, changes in consumption levels and the cost of natural gas from those forecast to set residential and commercial customer gas rates do not materially affect earnings.

Revenue

The decrease in revenue was primarily due to an overall lower cost of natural gas charged to customers in 2013 and decreases in the allowed ROE and the equity component of capital structure. The decrease was partially offset by an increase in the delivery component of customer rates effective January 1, 2013.

Earnings

Earnings were reduced by approximately $15 million as a result of the decreases in the allowed ROE and the equity component of capital structure. Excluding the impact of the lower allowed ROE and equity component of capital structure, earnings increased year over year, mainly due to lower-than-expected finance charges, lower operating and maintenance expenses, and rate base growth. The increases were partially offset by higher effective income taxes and lower gas transportation volumes.

Outlook

Final allowed ROEs and capital structures for FEVI and FEWI for 2013 and 2014 are subject to the outcome of the second stage of the GCOC Proceeding, which is expected in the first half of 2014. The regulatory process to review multi-year PBR applications, filed by the FortisBC Energy companies in 2013, will continue in 2014, with a decision expected in the third quarter. The expansion of FEI's Tilbury LNG facility, at an estimated total cost of approximately $400 million, began in 2013 and is expected to be in service in 2016.

Regulated Gas & Electric Utility – United States

Regulated Gas & Electric Utility – United States contributed earnings of $23 million for 2013, from the date of acquisition of CH Energy Group in June 2013, which represented approximately 6% of the Corporation's total regulated earnings. Regulated Gas & Electric Utility – United States assets were approximately $2.3 billion as at December 31, 2013, which represented approximately 14% of the Corporation's total regulated assets as at December 31, 2013.

Central Hudson

Financial Highlights (1)

Year Ended December 31	**2013**
Average US:CDN Exchange Rate (2)	**1.04**
Electricity Sales *(gigawatt hours ("GWh"))*	**2,629**
Gas Volumes *(PJ)*	**9**
Revenue *($ millions)*	**335**
Earnings *($ millions)*	**23**

(1) Financial results of Central Hudson are from June 27, 2013, the date of acquisition. For additional information on the acquisition of Central Hudson, refer to the "Significant Items – Acquisition of CH Energy Group" section of this MD&A.
(2) The reporting currency of Central Hudson is the US dollar.

Electricity Sales

Electricity sales year to date from acquisition were 2,629 gigawatt hours ("GWh") compared to 2,665 GWh for the same period last year. The decrease was mainly due to cooler temperatures in the third quarter of 2013.

Gas Volumes

Gas volumes year to date from acquisition were 9 petajoules ("PJ") compared to 12 PJ for the same period last year. The decrease was mainly due to lower volumes delivered to a power generating facility as a result of reduced facility operations and lower volumes for resale.

A portion of Central Hudson's electricity sales and gas volumes are to other entities for resale. Electricity sales for resale do not have an impact on earnings, as any related earnings are refunded to, or loss is collected from, customers. For gas volumes for resale, 85% of any related earnings are refunded to, or loss is collected from, customers.

Seasonality impacts the delivery revenue of Central Hudson, as electricity sales are highest during the summer months, primarily due to the use of air conditioning and other cooling equipment, and gas volumes are highest during the winter months, primarily due to space-heating usage.

Revenue

Revenue year to date was US$321 million compared to US$318 million for the same period last year. The increase was primarily due to higher electric and natural gas energy cost adjustment revenue, resulting from higher wholesale prices in the fourth quarter of 2013, combined with higher revenue from electricity energy-efficiency programs, partially offset by lower gas volumes.

Earnings

Earnings year to date were consistent with expectations and comparable with the same period last year.

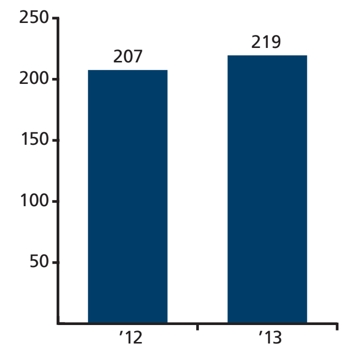
Outlook

Central Hudson's allowed ROE and capital structure are set at current levels through June 30, 2015, as approved by the regulator on acquisition in June 2013. In mid-2014 Central Hudson will file a general rate application, its first such application as a Fortis utility, to establish rates effective mid-2015. Regulatory approval of the acquisition of Central Hudson included a two-year delivery rate freeze through June 30, 2015. Over the same two-year period, Central Hudson committed to invest US$215 million in capital expenditures.

Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2013 were $219 million (2012 – $207 million), which represented approximately 56% of the Corporation's total regulated earnings (2012 – 57%). Regulated Electric Utilities – Canadian assets were approximately $7.5 billion as at December 31, 2013 (December 31, 2012 – $7.1 billion), which represented approximately 47% of the Corporation's total regulated assets as at December 31, 2013 (December 31, 2012 – 53%).

Regulated Electric Utilities – Canadian Earnings *($ millions)*



FortisAlberta

Financial Highlights

Years Ended December 31	2013	2012	Variance
Energy Deliveries *(GWh)*	**16,934**	16,799	135
Revenue *($ millions)*	**475**	448	27
Earnings *($ millions)*	**94**	96	(2)

Energy Deliveries

The increase in energy deliveries was driven by growth in the number of customers, partially offset by lower activity in the oil and gas industry. The total number of customers increased by approximately 10,000 year over year, mainly residential and commercial customers.

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

Revenue

The increase in revenue was primarily due to an interim increase in customer electricity distribution rates, effective January 1, 2013, associated with the decision received in March 2013 related to FortisAlberta's PBR Compliance Application, growth in the number of customers, and an increase in revenue related to flow-through items to customers. The increase in revenue was mitigated by net transmission revenue of approximately $8.5 million in 2012. As approved by the regulator in April 2012, FortisAlberta assumed the risk of volume variances related to net transmission costs during 2012. The deferral of transmission volume variances, however, was reinstated by the regulator effective January 1, 2013. Lower net transmission revenue was partially offset by approximately $2 million recognized in 2013 associated with the finalization of the 2012 net transmission volume variances.

Earnings

The decrease in earnings was mainly due to lower net transmission revenue of approximately $6.5 million and incremental restoration costs of $1.5 million related to flooding in southern Alberta in June 2013. The decrease was partially offset by rate base growth and growth in the number of customers. Earnings associated with rate base growth, however, were tempered by the interim regulatory decision granting 60% of the revenue requirement associated with the capital tracker component of the PBR Compliance Application in March 2013.

Outlook

FortisAlberta's final allowed ROE and capital structure for 2013 and 2014 remain to be determined, subject to the outcome of the GCOC Proceeding in Alberta. Uncertainty exists regarding the outcome of the Company's Capital Tracker Application and, as a result, 60% of the applied for capital tracker amount, as approved in the Interim Compliance Decision, will be retained. FortisAlberta is required to re-file its 2013 Capital Tracker Application in early 2014 in accordance with the prescribed format as issued by the regulator in December 2013. A decision is expected on the re-filed 2013 Capital Tracker Application by the end of 2014.

FortisBC Electric

Financial Highlights

Years Ended December 31	**2013**	2012	Variance
Electricity Sales *(GWh)*	**3,211**	3,143	68
Revenue *($ millions)*	**317**	306	11
Earnings *($ millions)*	**50**	50	–

Electricity Sales

The increase in electricity sales was driven by higher average consumption, due to colder temperatures mainly in the fourth quarter of 2013.

Revenue

The increase in revenue was primarily due to an increase in customer electricity rates effective January 1, 2013, revenue associated with the acquisition of the City of Kelowna's electrical utility assets in March 2013 and electricity sales growth. The increase was partially offset by differences in flow-through adjustments owing to customers period over period, including the impact of the decrease in the interim allowed ROE, effective January 1, 2013, as a result of the first stage of the GCOC Proceeding, a decrease in management fee revenue resulting from lower third-party activity and lower pole-attachment revenue.

Earnings

Earnings were favourably impacted by rate base growth, including the acquisition of the City of Kelowna's electrical utility assets in March 2013, and lower-than-expected finance charges and depreciation. The increase was largely offset by a decrease in the interim allowed ROE, which reduced earnings for the year by approximately $4 million, higher effective income taxes and lower pole-attachment revenue.

Outlook

FortisBC Electric's final allowed ROE and capital structure for 2013 and 2014 is subject to the outcome of the second stage of the GCOC Proceeding, which is expected in the first half of 2014. The regulatory process to review the multi-year PBR application, filed by FortisBC Electric in 2013, will continue in 2014, with a decision expected in the third quarter.

Newfoundland Power

Financial Highlights

Years Ended December 31	**2013**	2012	Variance
Electricity Sales *(GWh)*	**5,763**	5,652	111
Revenue *($ millions)*	**601**	581	20
Earnings *($ millions)*	**49**	37	12

Electricity Sales

The increase in electricity sales was primarily due to customer growth and higher average consumption, reflecting a higher concentration of electric-versus-oil heating in new home construction combined with economic growth. Colder weather conditions in the fourth quarter of 2013 also contributed to the increase in average consumption.

Revenue

The increase in revenue was primarily due to electricity sales growth and an increase in base electricity rates, effective July 1, 2013, as reflected in the 2013/2014 General Rate Application ("GRA") decision received in April 2013.

Earnings

The increase in earnings was driven by an approximate $13 million income tax recovery in 2013, due to the enactment of higher deductions associated with Part VI.1 tax, partially offset by the $2.5 million reversal of statute-barred Part VI.1 tax in 2012. Excluding the impact of Part VI.1 tax in both years, the increase in earnings was primarily due to rate base growth and an approximate $1 million gain on the sale of land in 2013.

Outlook

Continuing regulatory stability is expected at Newfoundland Power. As approved by the regulator, the Company's allowed ROE and equity component of capital structure will be maintained at current levels through the end of 2015.

Other Canadian Electric Utilities

Financial Highlights

Years Ended December 31	2013	2012	Variance
Electricity Sales *(GWh)*	**2,405**	2,381	24
Revenue *($ millions)*	**374**	353	21
Earnings *($ millions)*	**26**	24	2

Electricity Sales

The increase in electricity sales was driven by higher average consumption by residential customers on PEI, due to cooler temperatures and an increase in the number of customers using electricity for home heating. The increase was partially offset by lower average consumption by customers in Ontario reflecting more moderate temperatures, energy conservation and continuing weak economic conditions in the region.

Revenue

The increase in revenue was primarily due to electricity sales growth on PEI, an increase in the base component of customer rates at Maritime Electric, effective March 1, 2013, and the flow through in customer electricity rates of higher energy supply costs at FortisOntario. The increase was partially offset by the impact of the cumulative return adjustment on smart meter investments at FortisOntario in 2012 and lower electricity sales in Ontario in 2013. At Maritime Electric, a higher regulatory rate of return adjustment in 2013 compared to 2012 had an unfavourable impact on revenue year over year.

Earnings

The increase in earnings was driven by an approximate $4 million income tax recovery at Maritime Electric in 2013, due to the enactment of higher deductions associated with Part VI.1 tax, partially offset by the cumulative return adjustment on smart meter investments at FortisOntario in 2012.

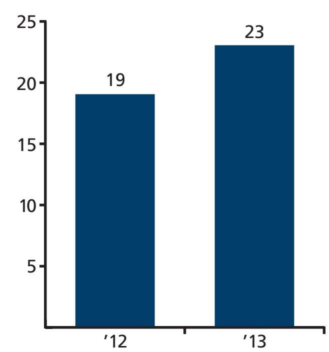
Outlook

Continuing regulatory stability is expected at Other Canadian Electric Utilities. As approved by the regulator, Maritime Electric's allowed ROE and capital structure have been set for the three-year period ending February 29, 2016. Canadian Niagara Power and Algoma Power's allowed ROEs for 2014 remain unchanged from 2013.

Regulated Electric Utilities – Caribbean

Regulated Electric Utilities – Caribbean earnings for 2013 were $23 million (2012 – $19 million), which represented approximately 6% of the Corporation's total regulated earnings (2012 – 5%). Regulated Electric Utilities – Caribbean assets were approximately $0.8 billion as at December 31, 2013 (December 31, 2012 – $0.8 billion), which represented approximately 5% of the Corporation's total regulated assets as at December 31, 2013 (December 31, 2012 – 6%).

Regulated Electric Utilities – Caribbean Earnings *($ millions)*



Financial Highlights

Years Ended December 31	2013	2012	Variance
Average US:CDN Exchange Rate [(1)]	**1.03**	1.00	0.03
Electricity Sales *(GWh)*	**749**	728	21
Revenue *($ millions)*	**290**	273	17
Earnings *($ millions)*	**23**	19	4

(1) The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar.

Electricity Sales

The increase in electricity sales was primarily due to warmer temperatures experienced on Grand Cayman, which increased air conditioning load, and growth in the number of customers. Increased electricity sales at Fortis Turks and Caicos were mainly due to electricity sales of 21 GWh in 2013 at TCU. Electricity sales in 2012 at TCU were approximately 8 GWh from the date of acquisition in August 2012.

Revenue

The increase in revenue was primarily due to approximately $9 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, due to the strengthening of the US dollar relative to the Canadian dollar year over year. Electricity sales growth and a 1.8% increase in base customer electricity rates at Caribbean Utilities, effective June 1, 2013, also favourably impacted revenue year over year.

Earnings

The increase in earnings was driven by the capitalization of overhead costs of approximately $3 million at Fortis Turks and Caicos, as approved by the Government of the Turks and Caicos Islands in December 2013. Electricity sales growth and the 1.8% increase in base customer electricity rates at Caribbean Utilities also contributed to the increase in earnings, partially offset by higher overall depreciation expense.

Outlook

Electricity sales at Caribbean Utilities and Fortis Turks and Caicos are expected to increase 2% and 5%, respectively, in 2014. The recovery from the global economic recession continues to be slow, with economic challenges still being faced in the Caribbean region. Expected electricity sales growth reflects the completion of certain local development projects in 2014, mainly in the Turks and Caicos Islands. For further information, refer to the "Business Risk Management – Economic Conditions" section of this MD&A.

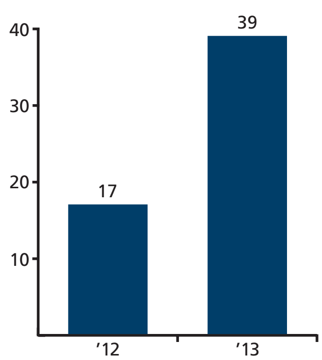
NON-REGULATED

Non-Regulated – Fortis Generation

Financial Highlights

Years Ended December 31	**2013**	2012	Variance
Energy Sales *(GWh)*	**386**	306	80
Revenue *($ millions)*	**35**	31	4
Earnings *($ millions)*	**39**	17	22

Non-Regulated –
Fortis Generation Earnings
($ millions)



Energy Sales

The increase in energy sales was driven by increased production in Belize, due to higher rainfall. Production in Ontario and Upstate New York also contributed to the increase, due to higher rainfall and a generating unit in Upstate New York being returned to service in October 2013, respectively.

Revenue

The increase in revenue was driven by increased production in Belize, due to higher rainfall.

Earnings

The increase in earnings was driven by an approximate $20 million after-tax extraordinary gain on the settlement of expropriation matters associated with the Exploits Partnership and increased production in Belize.

Outlook

Construction of the non-regulated Waneta Expansion in British Columbia will continue in 2014 and is expected to be completed in spring 2015. Once completed, the Waneta Expansion is expected to more than double annual earnings from the Non-Regulated – Fortis Generation segment from the expected 2014 earnings level.

Non-Regulated – Non-Utility

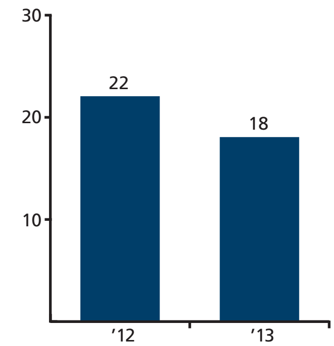
Financial Highlights [1]

Years Ended December 31

($ millions)	**2013**	2012	Variance
Revenue	**248**	242	6
Earnings	**18**	22	(4)

[1] Financial results of Griffith are from June 27, 2013, the date of acquisition. The reporting currency of Griffith is the US dollar. In March 2014 CH Energy Group sold Griffith. For further details on the sale, refer to the "Significant Items – Sale of Griffith" section of this MD&A. As such, the results of operations of Griffith have been presented as discontinued operations on the consolidated statement of earnings and, accordingly, revenue excludes amounts associated with Griffith. Earnings, however, reflect the results of operations of Griffith.

Non-Regulated – Non-Utility Earnings *($ millions)*



Revenue

The increase in revenue was primarily due to improved performance at Fortis Properties' Hospitality Division, driven by an increase in the average daily room rate in all regions, and Real Estate Division, mainly due to the recovery of business occupancy tax from certain tenants in 2013 and higher occupancy. Revenue for 2013 also reflects a full year of contribution from the StationPark All Suite Hotel, which was acquired in October 2012.

Earnings

Earnings at Fortis Properties were $23 million for 2013. The net loss at the non-regulated operations of CH Energy Group year to date from acquisition was approximately $5 million.

The $1 million increase in earnings at Fortis Properties was primarily due to improved performance at the Hospitality Division, partially offset by higher depreciation due to capital additions and improvements.

The net loss at the non-regulated operations of CH Energy Group was primarily due to approximately $3.5 million in deferred income tax expenses associated with no longer recognizing CH Energy Group's combined filing tax benefit, which is not expected to be realized due to the sale of Griffith. Year to date from acquisition, earnings from discontinued operations at Griffith were nil.

Outlook

Modest revenue growth is projected at Fortis Properties' Hospitality Division in 2014. In 2014 Fortis Properties' Real Estate Division is expected to produce stable results with the completion of construction of a new 12-storey office building in downtown St. John's expected by mid-2014. For a discussion of the impact of economic conditions on Fortis Properties' operations, refer to the "Business Risk Management – Economic Conditions" section of this MD&A.

Corporate and Other

Financial Highlights

Years Ended December 31 *($ millions)*	2013	2012	Variance
Revenue	**26**	24	2
Operating Expenses	**13**	14	(1)
Depreciation and Amortization	**2**	2	–
Other Income (Expenses), Net	**(45)**	(9)	(36)
Finance Charges	**48**	47	1
Income Tax Recovery	**(43)**	(7)	(36)
	(39)	(41)	2
Preference Share Dividends	**57**	47	10
Net Corporate and Other Expenses	**(96)**	(88)	(8)

Net Corporate and Other expenses were significantly impacted by the following items:

(i) other expenses of approximately $41 million (US$40 million), or $26 million (US$26 million) after tax, associated with customer and community benefits offered by the Corporation to close the acquisition of CH Energy Group were recognized in 2013;

(ii) other expenses of $9 million ($6 million after tax) in 2013 related to the acquisition of CH Energy Group compared to approximately $9 million ($7.5 million after tax) in 2012;

(iii) other expenses of $3 million ($2 million after tax) in 2013 related to the pending acquisition of UNS Energy;

(iv) a foreign exchange gain of $6 million in 2013, compared to a foreign exchange loss of $2 million in 2012, associated with the Corporation's US dollar-denominated long-term other asset, representing the book value of the Corporation's expropriated investment in Belize Electricity;

(v) a $6 million income tax recovery in 2013, due to the enactment of higher deductions associated with Part VI.1 tax, compared to $6 million in income tax expense in 2012 associated with Part VI.1 tax; and

(vi) the release of income tax provisions of approximately $7 million in 2013 compared to $4 million in 2012.

Excluding the above-noted items, net Corporate and Other expenses were $81 million for 2013 compared to approximately $77 million for 2012. The increase was primarily due to higher preference share dividends and higher finance charges, partially offset by a higher income tax recovery and lower operating expenses. Higher preference share dividends were due to: (i) the issuance of First Preference Shares, Series J in November 2012; (ii) the issuance of First Preference Shares, Series K in July 2013; and (iii) approximately $2 million of costs associated with the redemption of First Preference Shares, Series C in July 2013. The increase was partially offset by lower preference share dividends due to the redemption of First Preference Shares, Series C in July 2013 and a decrease in the annual fixed dividend rate on the First Preference Shares, Series G effective September 2013. Higher finance charges associated with the CH Energy Group acquisition were partially offset by higher capitalized interest associated with the financing of the construction of the Waneta Expansion.

Outlook

Fortis is focused on closing the UNS Energy acquisition by the end of 2014. The Corporation expects to incur approximately $72 million ($51 million after tax) in financing costs associated with the Debentures issued in January 2014 to finance a portion of the pending acquisition. Corporate and Other expenses in 2014 will also be impacted by other acquisition-related costs associated with the pending acquisition, which could be material. For further information, refer to the "Significant Items – Pending Acquisition of UNS Energy" and "Significant Items – Convertible Debentures Represented by Installment Receipts" sections of this MD&A.

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities are summarized as follows.

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2011	2012	2013	Supportive Features / Future or Historical Test Year Used to Set Customer Rates
				ROE		
FEI	British Columbia Utilities Commission ("BCUC")	38.5 (1)	9.50	9.50	8.75	COS/ROE FEI: Prior to January 1, 2010, 50%/50% sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009 with a two-year phase-out ROEs established by the BCUC – 2013 ROEs for FEVI and FEWI are under review Future test year
FEVI	BCUC	40 (2)	10.00	10.00	9.25 (2)	
FEWI	BCUC	40 (2)	10.00	10.00	9.25 (2)	
FortisBC Electric	BCUC	40 (2)	9.90	9.90	9.15 (2)	COS/ROE PBR mechanism for 2009 through 2011: 50%/50% sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC – 2013 ROE is under review Future test year
Central Hudson	PSC	48 (3)	10.00	10.00	10.00 (3)	COS/ROE Earnings sharing mechanism effective July 1, 2013: 50%/50% sharing of earnings above the allowed ROE up to 50 basis points above the allowed ROE; and 10%/90% sharing of earnings in excess of 50 basis points above the allowed ROE ROE established by the PSC Future Test Year
FortisAlberta	Alberta Utilities Commission ("AUC")	41 (4)	8.75	8.75	8.75 (4)	COS/ROE PBR mechanism for 2013 through 2017 with capital tracker account and other supportive features ROE established by the AUC – 2013 ROE is under review 2012 test year with 2013 through 2017 rates set using PBR mechanism
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	8.38 +/– 50 bps	8.80 +/– 50 bps	8.80 +/– 50 bps	COS/ROE The allowed ROE was set using an automatic adjustment formula tied to long-term Canada bond yields for 2011. ROE established by the PUB for 2012 through 2015 Future test year
Maritime Electric	Island Regulatory and Appeals Commission	40	9.75	9.75	9.75	COS/ROE Future test year
FortisOntario	Ontario Energy Board ("OEB")					
	Canadian Niagara Power	40	8.01	8.01	8.93 (5)	Canadian Niagara Power – COS/ROE
	Algoma Power	40	9.85	9.85	9.85 (5)	Algoma Power – COS/ROE and subject to Rural and Remote Rate Protection ("RRRP") Program
	Franchise Agreement Cornwall Electric					Cornwall Electric – Price cap with commodity cost flow through Canadian Niagara Power – 2009 test year for 2011 and 2012; 2013 test year for 2013 Algoma Power – 2011 test year for 2011, 2012 and 2013
				ROA		
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	7.75 – 9.75	7.25 – 9.25	6.50 – 8.50	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices The Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane. Historical test year
Fortis Turks and Caicos	Utilities make annual filings to the Government of the Turks and Caicos Islands	N/A	17.50 (6)	17.50 (6)	17.50 (6)	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the utilities may apply for an increase in customer rates in the following year. Future test year

(1) Effective January 1, 2013. For 2011 and 2012, the allowed equity component of the capital structure was 40%.
(2) Capital structures and allowed ROEs for 2013 are interim and are subject to change based on the outcome of the second stage of the GCOC Proceeding. The allowed ROEs for 2013 reflect the benchmark 8.75% allowed ROE for FEI, as set by the BCUC, and risk premiums associated with each of these utilities.
(3) Effective until June 30, 2015
(4) Capital structure and allowed ROE for 2013 are interim and are subject to change based on the outcome of a cost of capital proceeding.
(5) Based on the ROE automatic adjustment formula, the allowed ROE for regulated electric utilities in Ontario is 8.93% for 2013. This ROE is not applicable to the regulated electric utilities until they are scheduled to file full COS rate applications. As a result, the allowed ROE of 8.93% is not applicable to Algoma Power for 2013.
(6) Amount allowed under licences as it relates to FortisTCI. Amount allowed under licence for TCU is 15%. Achieved ROAs at the utilities were significantly lower than those allowed under licences as a result of the inability, due to economic and political factors, to increase base customer electricity rates associated with significant capital investment in recent years.

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
FEI/FEVI/FEWI	• Effective January 1, 2013, as approved by the BCUC in its April 2012 decision pertaining to the FortisBC Energy companies' 2012/2013 Revenue Requirements Application ("RRA"), customer delivery rates increased 8.7% at FEI and 5.5% at FEWI. The rate increases were due to ongoing investment in energy infrastructure and forecast increases in operating expenses. Customer delivery rates at FEVI remained unchanged. • The public hearing for the first stage of a GCOC Proceeding to determine the allowed ROE and appropriate capital structure for FEI, the designated low-risk benchmark utility in British Columbia, occurred in December 2012. In May 2013 the BCUC issued its decision on the first stage of the GCOC Proceeding. Effective January 1, 2013, the decision set the ROE of the benchmark utility at 8.75%, compared to 9.50% for 2012, with a 38.5% equity component of capital structure, compared to 40% for 2012. The equity component of capital structure will remain in effect until December 31, 2015. Effective January 1, 2014 through December 31, 2015, the BCUC is also introducing an Automatic Adjustment Mechanism ("AAM") to set the allowed ROE for the benchmark utility on an annual basis. The AAM will take effect when the long-term Government of Canada bond yield exceeds 3.8%. In January 2014 the BCUC confirmed that the necessary conditions for the AAM to be triggered for the 2014 allowed ROE have not been met; therefore, the benchmark allowed ROE remains at 8.75% for 2014. FEVI, FEWI and FortisBC Electric will have their allowed ROEs and capital structures determined in the second stage of the GCOC Proceeding. As a result of the BCUC's decision on the first stage of the GCOC Proceeding, which reduced the allowed ROE of the benchmark utility by 75 basis points, the interim allowed ROEs for FEVI, FEWI and FortisBC Electric decreased to 9.25%, 9.25% and 9.15%, respectively, effective January 1, 2013, while the deemed equity component of capital structures remained unchanged. The allowed ROEs and equity component of capital structures for FEVI, FEWI and FortisBC Electric could change further as a result of the outcome of the second stage of the GCOC Proceeding. In March 2013 the BCUC initiated the second stage of the GCOC Proceeding. The companies filed risk premium and equity ratio evidence in July 2013. The evidentiary phase has been completed and a decision is expected in the first half of 2014. • In June 2013 FEI filed an application with the BCUC for a Multi-Year PBR Plan for 2014 through 2018. Pursuant to an Evidentiary Update filed in September 2013, the application assumes a 2014 forecast midyear rate base for FEI of approximately $2,789 million. The application also requests approval of a delivery rate increase for 2014 of approximately 1.4%, determined under a formula approach for operating and capital costs, and a continuation of this rate-setting methodology for a further four years. Effective January 1, 2014, the BCUC has approved a 1.4% interim refundable delivery rate increase. The regulatory process to review the application will continue in 2014, with a decision expected in the third quarter of 2014. • In April 2012 the FortisBC Energy companies applied to the BCUC for the necessary approvals to amalgamate the three utilities and implement common rates across the service territories served by the amalgamated entity for 2014. In February 2014 the BCUC determined that the amalgamation of the FortisBC Energy companies will move forward. • In September 2013 FEVI filed an application for Revenue Requirements and Rates for 2014, proposing to hold 2014 rates at existing levels. The review process is underway and a decision is expected in the first quarter of 2014. In October 2013 FEWI also filed an application for Revenue Requirements and Rates for 2014, proposing to hold 2014 rates at existing levels, which was approved in December 2013. • In November 2013 the Government of British Columbia signed an Order in Council ("Special Direction") setting out a number of requirements for the BCUC as follows: (i) to allow FEI to provide CNG and LNG service as part of its natural gas service; (ii) to exempt the expansion of FEI's Tilbury LNG facilities from a Certificate of Public Convenience and Necessity ("CPCN") process; and (iii) to approve a permanent LNG sales and dispensing service for FEI at the rate set out in the Special Direction. • In August 2011 FEI received a BCUC decision on the use of Energy Efficiency and Conservation ("EEC") funds as incentives for natural gas-fuelled vehicles ("NGVs"). FEI had made these funds available to assist large customers to purchase NGVs in lieu of vehicles fuelled by diesel. The decision determined that it was not appropriate to use EEC funds for this purpose and the BCUC requested that FEI provide further submissions to determine the prudency of the EEC incentives at a future time. An application was filed with the BCUC to review the prudency of the EEC incentives and a decision was received in April 2013 in which the BCUC determined that the EEC incentives for NGVs were prudently incurred and can be recovered from customers in rates as part of the incentive funding under the Greenhouse Gas Reductions (Clean Energy) Regulation ("GGRR") under the *Clean Energy Act* that was announced in May 2012. • In February 2012 the BCUC approved FEI's amended application for a general tariff for the provision of CNG and LNG refuelling services for transportation vehicles. FEI has received either permanent or interim rate approval for four refuelling projects. In addition, FEI and FEVI have received BCUC approval for rate treatment of expenditures under the GGRR. FEI has also received approval for one of two refuelling stations applied for under the GGRR with a decision pending on the second refuelling station. FEVI has received approval for its first refuelling station under the GGRR. • FAES has received BCUC approval for the capital expenditures related to three thermal energy projects: PCI Marine Gateway, TELUS Garden and Kelowna District Energy System.
FortisBC Electric	• Refer to the FEI/FEVI/FEWI section of this "Material Regulatory Decisions and Applications" table for details on the second stage of the GCOC Proceeding as it relates to FortisBC Electric. • Effective January 1, 2013, as approved by the BCUC in its August 2012 decision pertaining to FortisBC Electric's 2012/2013 RRA, customer electricity rates increased 4.2%. The rate increase was due to ongoing investment in energy infrastructure, including increased costs of financing the investment, and increased power purchase costs.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisBC Electric (cont'd)	• In July 2013 the BCUC approved FortisBC Electric's Advanced Metering Infrastructure ("AMI") project for a total cost of approximately $51 million. In December 2013 the BCUC approved the Company's Radio-Off Meter Option Application, which requires that the incremental cost of opting out of AMI be borne by customers who choose to opt out. • In March 2013 the BCUC approved the acquisition by FortisBC Electric of the City of Kelowna's electrical utility assets and allowed for approximately $38 million of the $55 million purchase price to be included in FortisBC Electric's rate base, resulting in the recognition of approximately $14 million of goodwill and a $3 million deferred income tax asset. The acquisition closed in March 2013. • In July 2013 FortisBC Electric filed an application with the BCUC for a Multi-Year PBR Plan for 2014 through 2018. Pursuant to an Evidentiary Update filed in October 2013, the application assumes a 2014 forecast midyear rate base of approximately $1,192 million. The application also requests approval of a base customer rate increase for 2014 of approximately 3.3%, determined under a formula approach for operating and capital costs, and a continuation of this rate-setting methodology for a further four years. Effective January 1, 2014, the BCUC has approved a 3.3% interim refundable base rate increase. The regulatory process to review the application will continue in 2014, with a decision expected in the third quarter of 2014.
Central Hudson	• In June 2013 the PSC approved the acquisition of Central Hudson by Fortis. To obtain this regulatory approval, Fortis committed to provide Central Hudson's customers and community with approximately US$50 million in financial benefits. These incremental benefits include: (i) US$35 million to cover expenses that would normally be recovered in customer rates; (ii) guaranteed savings to customers of more than US$9 million over five years resulting from the elimination of costs CH Energy Group would otherwise incur as a public company; and (iii) the establishment of a US$5 million Community Benefit Fund to be used for low-income customer and economic development programs for communities and residents of the Mid-Hudson River Valley. In addition, a delivery rate freeze was implemented for electricity and natural gas customers through to June 30, 2015. Central Hudson committed to invest US$215 million in capital expenditures over the same two-year period.
FortisAlberta	• Effective January 1, 2013, the AUC prescribed that distribution utilities in Alberta, including FortisAlberta, move to a PBR framework for a five-year term. Under the PBR framework, a formula that estimates inflation annually and assumes productivity improvements is used to determine customer distribution rates on an annual basis. The PBR framework also includes mechanisms for the recovery or settlement of items determined to flow through directly to customers and the recovery of costs related to capital expenditures that are not being recovered through the inflationary factor of the formula. The AUC also approved: (i) a Z factor permitting an application for recovery of costs related to significant unforeseen events; (ii) a PBR re-opener mechanism permitting an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan; and (iii) an ROE efficiency carry-over mechanism permitting an efficiency incentive by allowing the utility to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of the term. The PBR formula does, however, raise some concern and uncertainty for FortisAlberta regarding the treatment of certain capital expenditures. While the PBR Decision did provide for a capital tracker mechanism for the recovery of costs related to certain capital expenditures, FortisAlberta sought further clarification regarding this mechanism in a Compliance Application and a Review and Variance ("R&V") Application, both filed in November 2012, and sought leave to appeal the issue with the Alberta Court of Appeal. FortisAlberta filed a 2013 Capital Tracker Application for specific categories of capital expenditures in December 2012. • In March 2013 the AUC issued a decision denying the R&V Application. FortisAlberta filed a leave to appeal the denial on similar grounds as the leave to appeal the PBR Decision. Both appeals have been adjourned pending further determinations in outstanding PBR-related proceedings. • In March 2013 the AUC issued an interim decision regarding the Compliance Applications filed by the distribution utilities in Alberta. The interim decision approved a combined inflation and productivity factor of 1.71%, certain adjustments to the Company's going-in rates, including deferral amounts and a placeholder equal to 60% of the applied for 2013 capital tracker amount. For FortisAlberta, the AUC approved approximately $14.5 million of the $24 million in revenue requested in the utility's 2013 Capital Tracker Application. The decision resulted in an interim increase in FortisAlberta's distribution rates of approximately 4%, effective January 1, 2013, with collection from customers commencing April 1, 2013. A final decision on the Compliance Application was received in July 2013 directing the Company to continue to use interim rates until the capital tracker placeholder is finalized. • In December 2013 the AUC issued a Capital Tracker Decision which requires certain utilities in Alberta, including FortisAlberta, to re-file their 2013 Capital Tracker Applications by May 2014 using a prescribed format. The Capital Tracker Decision provides clarification on the following criteria that must be satisfied in order for a project to be included in the capital tracker, as set out in the original PBR Decision: (i) the project must be outside the normal course of the Company's ongoing operations; (ii) ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party; and (iii) the project must have a material effect on the Company's finances. FortisAlberta continues to evaluate its compliance with the AUC-prescribed approach. In the interim, the Company has been directed by the AUC to retain the placeholder equal to 60% of the applied for capital tracker amount as approved in the Interim Compliance Decision. A decision is expected on the re-filed 2013 Capital Tracker Application by the end of 2014. The Capital Tracker Decision also directs utilities in Alberta to file a combined 2014 and 2015 Capital Tracker Application by March 2014. Generally, capital tracker applications will be filed each March for projects planned for the subsequent year; however, given that a decision on the 2013 Capital Tracker Application was outstanding in 2013, the AUC delayed the filing of the 2014 Capital Tracker Application.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In September 2013 FortisAlberta filed its 2014 Annual Rates Filing. The rates and riders, proposed to be effective on an interim basis for January 1, 2014, include a 5.36% increase to the distribution component of customer rates. This increase reflects a combined inflation and productivity factor of 1.59%, a capital tracker placeholder of 60% applied to the capital expenditure forecast for 2014 and a net refund of flow-through balances. In December 2013 the application was approved, on an interim basis, as filed. The 2014 rates will remain interim until a final decision is received regarding capital trackers. • In October 2012 the AUC initiated a 2013 GCOC Proceeding to establish the final allowed ROE for 2013 and determine whether a formulaic ROE automatic adjustment mechanism should be re-established. In November 2012 the 2013 GCOC Proceeding was suspended until other regulatory matters were resolved. In April 2013 the AUC recommenced the 2013 GCOC Proceeding to set the allowed ROE and capital structure for distribution utilities in Alberta for 2013, as well as the allowed ROE for 2014. In this proceeding the AUC may consider the possibility of re-establishing a formula-based approach to setting annual ROE beyond 2014. A hearing is scheduled for the second quarter of 2014. • In November 2013 the AUC issued its decision regarding the Utility Asset Disposition ("UAD") Proceeding. The decision confirmed that no changes to existing regulations, rules and practices relative to the recovery of utility asset costs in the ordinary course of business are required. However, the decision indicated that Alberta utilities will be responsible for the gains and losses related to extraordinary retirement of utility assets, although it is uncertain how the AUC will determine those types of requirements. The decision indicated that a further review of charges associated with customer-specific facilities will be undertaken and that a review of each utility's rate base, as part of its next revenue requirement filing, will be required to confirm that all assets continue to be used in the provision of the utility service. FortisAlberta believes that the UAD Decision does not provide sufficient certainty to conclude that the AUC has properly interpreted and applied the Company's statutory rights to recover the prudently incurred costs and expenses of its capital investment in the electric utility. Consequently, FortisAlberta, as have other Alberta utilities, filed a leave to appeal the UAD Decision with the Alberta Court of Appeal. • In January 2013 FortisAlberta filed a Phase II Distribution Tariff Application ("Phase II DTA"), which proposed rates by customer class based on a cost allocation study and requested that the 2012 interim distribution rates by customer class be made final for 2012 and 2013, subject to further adjustments as a result of the PBR Decision and determinations in the outstanding PBR-related proceedings. In January 2014 the Company's Phase II DTA was approved by the AUC substantially as filed.
Newfoundland Power	• In April 2013 the PUB issued its decision related to Newfoundland Power's 2013/2014 GRA to establish the Company's cost of capital for rate-making purposes. In its decision, the PUB ordered that the allowed ROE and common equity component of capital structure remain at 8.8% and 45%, respectively, for 2013 through 2015. The 2013/2014 GRA also provided for certain revenue and cost changes, as well as the amortization of certain regulatory assets and liabilities and the creation of a conservation and demand management cost deferral. The impact of the decision resulted in an overall average increase in customer electricity rates of approximately 4.8% effective July 1, 2013 and the deferral of approximately $4 million of costs incurred in 2013 but not recovered from customers, due to the timing of collection in customer rates. The operation of the AAM, which historically adjusted the Company's allowed ROE on an annual basis, has been suspended until the next GRA, which Newfoundland Power is required to file on or before June 1, 2015 to establish customer electricity rates for 2016. • Effective July 1, 2013, the PUB approved an overall average decrease in Newfoundland Power's customer electricity rates of approximately 3.1% to reflect the combined impact of the annual operation of Newfoundland Power's Rate Stabilization Account ("RSA") and the above-noted GRA decision. Through the annual operation of Newfoundland Hydro's Rate Stabilization Plan, variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power are captured and flowed through to customers through the operation of the Company's RSA. As a result of a decrease in the forecast cost of oil to be used to generate electricity at Newfoundland Hydro, customer electricity rates decreased approximately 7.9% effective July 1, 2013. The RSA also captures variances in certain of Newfoundland Power's costs, such as pension and energy supply costs. The decrease in customer rates as a result of the operation of the RSA did not impact Newfoundland Power's earnings in 2013.
Maritime Electric	• In December 2012 the *Electric Power (Energy Accord Continuation) Amendment Act* ("*Accord Continuation Act*") was enacted, which sets out the inputs, rates and other terms for the continuation of the PEI Energy Accord for an additional three years covering the period March 1, 2013 through February 29, 2016. Under the terms of the *Accord Continuation Act*, Maritime Electric received, in March 2013, proceeds of approximately $47 million from the Government of PEI upon its assumption of Maritime Electric's $47 million regulatory asset related to certain deferred incremental replacement energy costs during the refurbishment of the New Brunswick Power ("NB Power") Point Lepreau nuclear generating station ("Point Lepreau"). Over the above-noted three-year period, increases in electricity costs for a typical residential customer have been set at 2.2%, effective March 1 annually, and Maritime Electric's allowed ROE has been capped at 9.75% each year. The resulting customer rate increases are primarily due to higher COS and the collection from customers by Maritime Electric, acting as an agent on behalf of the Government of PEI, of Point Lepreau-related costs assumed by the Government of PEI. The proceeds were used by Maritime Electric to repay short-term borrowings, to pay a special dividend to Fortis to maintain the utility's capital structure and to finance its capital expenditure program.
FortisOntario	• Effective January 1, 2013, residential customer rates in Fort Erie, Gananoque and Port Colborne increased by an average of 6.8%, 5.9% and 7.4%, respectively. The rate increases were the result of the OEB's decision pertaining to FortisOntario's 2013 COS Application using a 2013 forward test year and the recovery of smart meter costs and stranded assets related to conventional meters and reflect an allowed ROE of 8.93%.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• In March 2013 the OEB issued its decision on Algoma Power's Third-Generation Incentive-Regulation Mechanism ("IRM") Application for customer electricity distribution rates and smart meter cost recovery, effective January 1, 2013, resulting in an overall increase in residential and commercial customer distribution rates of 3.75%. Residential and commercial customer distribution rates are adjusted by the average increase in customer rates of all other distributor rate changes in Ontario in the most recent rate year. The difference in the recovery of COS in residential and commercial customer distribution rates and the revenue requirement is compensated from RRRP program funding. Recovery of smart meter costs allocated to residential customers will also be recovered from RRRP program funding as ordered by the OEB. Total RRRP program funding for 2013 was approximately $12 million. • In August 2013 Canadian Niagara Power and Algoma Power filed applications with the OEB requesting approval for customer electricity distribution rates, effective January 1, 2014, based on the Fourth-Generation IRM. Under the Fourth-Generation IRM, which is effective for utilities in Ontario on or after January 1, 2014, in non-rebasing years customer electricity distribution rates are set using inflationary factors less a productivity factor. • In January 2014 the OEB issued its Decision and Order for Canadian Niagara Power under the Fourth-Generation IRM, resulting in a Generation Incentive Price Index of 1.25%, effective January 1, 2014. • In February 2014 the OEB issued its Decision and Order for Algoma Power under the Fourth-Generation IRM, resulting in a Generation Incentive Price Index of 1.4%, effective January 1, 2014, which was implemented on March 1, 2014.
Caribbean Utilities	• In December 2013 the ERA approved Caribbean Utilities' 2014–2018 Capital Investment Plan for US$143 million related to non-generation installation capital expenditures. Capital expenditures relating to additional generation installation are subject to ERA approval through a competitive bid process. • A Certificate of Need was filed with the ERA by Caribbean Utilities in October 2013 for generating capacity related to the upcoming retirements of some of the Company's generating units due to begin in 2014. The Certificate of Need listed a requirement of 36 MW of generating capacity to be operational in the first half of 2016. In November 2013 the ERA issued a solicitation for Statements of Qualifications from prospective bidders and in January 2014 the ERA announced the listing of qualified bidders and issued a request for proposals. • Effective June 1, 2013, following review and approval by the ERA, Caribbean Utilities' base customer electricity rates increased by 1.8% as a result of changes in the applicable consumer price indices and the utility's applicable targeted allowed ROA for the 2013 rate adjustment.
Fortis Turks and Caicos	• In March 2013 the Fortis Turks and Caicos utilities submitted their 2012 annual regulatory filings outlining performance in 2012. Included in the filings were the calculations, in accordance with the utilities' licences, of rate base of US$195 million for 2012 and cumulative shortfall in achieving allowable profits of US$105 million as at December 31, 2012. • In December 2013 the Government of the Turks and Caicos Islands approved FortisTCI's application to capitalize overhead costs not directly attributable to specific utility capital assets, but which relate to the Company's overall capital expenditure program. As a result, FortisTCI capitalized overhead costs of approximately $3 million in 2013, which represents 14% of overhead costs effective from January 1, 2013.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2013 and December 31, 2012.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2013 and December 31, 2012

Balance Sheet Account	Increase Due to CH Energy Group *($ millions)*	Other Increase/ (Decrease) *($ millions)*	Explanation for Other Increase/(Decrease)
Cash and cash equivalents	19	(101)	The decrease was primarily due to lower cash on hand at FortisAlberta and the FortisBC Energy companies.
Accounts receivable	104	41	The increase was primarily due to an increase in the base component of rates at most of the regulated utilities, and higher electricity sales and gas volumes.
Regulatory assets – current and long-term	227	(105)	The decrease was mainly due to: (i) a decrease in the employee future benefits deferral due to lower defined benefit pension and other post-employment benefits ("OPEBs") plan liabilities; (ii) proceeds of approximately $47 million received from the Government of PEI in March 2013 upon its assumption of Maritime Electric's replacement energy deferral associated with Point Lepreau; and (iii) the change in the deferral of the fair value of natural gas derivatives at the FortisBC Energy companies. The decrease was partially offset by higher regulatory deferred income taxes and the deferral of various other costs, as permitted by the regulators, mainly at the FortisBC Energy companies and FortisAlberta.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2013 and December 31, 2012 (cont'd)

Balance Sheet Account	Increase Due to CH Energy Group (*$ millions*)	Other Increase/ (Decrease) (*$ millions*)	Explanation for Other Increase/(Decrease)
Assets held for sale	112	–	Assets held for sale relate to the sale of Griffith in March 2014.
Utility capital assets	1,311	684	The increase primarily related to: (i) utility capital expenditures; (ii) the impact of foreign exchange on the translation of US dollar-denominated utility capital assets; and (iii) the acquisition of the City of Kelowna's electrical utility assets by FortisBC Electric. The above increases were partially offset by depreciation and customer contributions during 2013.
Goodwill	483	24	The increase related to $14 million in goodwill associated with the acquisition of the City of Kelowna's electrical utility assets by FortisBC Electric, and the impact of foreign exchange on the translation of US dollar-denominated goodwill.
Accounts payable and other current liabilities	84	(93)	The decrease was mainly due to: (i) lower accounts payable associated with transmission-connected projects and timing of Alberta Electric System Operator ("AESO") payments for transmission costs at FortisAlberta; (ii) the change in the fair value of natural gas derivatives at the FortisBC Energy companies; and (iii) the reversal of income tax liabilities associated with Part VI.1 tax. The decrease was partially offset by an increase in gas and fuel costs payable and higher purchased power costs due to higher electricity sales and gas volumes.
Regulatory liabilities – current and long-term	231	58	The increase was primarily due to the AESO charges deferral account at FortisAlberta and an increase in the provision for non-asset retirement obligation ("ARO") removal costs, mainly at FortisAlberta and the FortisBC Energy companies.
Long-term debt (including current portion)	550	754	The increase was driven by: (i) the issuance of long-term debt, including US$325 million at the Corporation, $150 million at FortisAlberta, $70 million at Newfoundland Power, and US$50 million at Caribbean Utilities; (ii) higher committed credit facility borrowings, mainly at the Corporation, to finance a portion of the acquisition of CH Energy Group, and at FortisBC Electric to finance a portion of the acquisition of the City of Kelowna's electrical utility assets; and (iii) the impact of foreign exchange on the translation of US-dollar denominated debt. The increase was partially offset by regularly scheduled debt repayments.
Liabilities associated with assets held for sale	32	–	Liabilities associated with assets held for sale relate to the sale of Griffith in March 2014.
Deferred income tax liabilities – current and long-term	294	80	The increase was driven by tax timing differences related mainly to capital expenditures at the regulated utilities.
Other liabilities	106	(117)	The decrease was primarily due to a decrease in defined benefit pension and OPEB plan liabilities, mainly due to higher discount rates as at December 31, 2013, and an increase in plan assets.
Shareholders' equity (before non-controlling interests)	–	901	The increase primarily related to: (i) the conversion of Subscription Receipts into common shares in June 2013 for net after-tax proceeds of $567 million to finance a portion of the acquisition of CH Energy Group; (ii) the issuance of First Preference Shares, Series K in July 2013 for net after-tax proceeds of $244 million; (iii) net earnings attributable to common equity shareholders for 2013, less dividends declared on common shares; and (iv) the issuance of common shares under the Corporation's Dividend Reinvestment Plan. The above-noted increases were partially offset by the redemption of First Preference Shares, Series C in July 2013 for $125 million.
Non-controlling interests	–	65	The increase was driven by advances from the 49% non-controlling interests in the Waneta Partnership.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

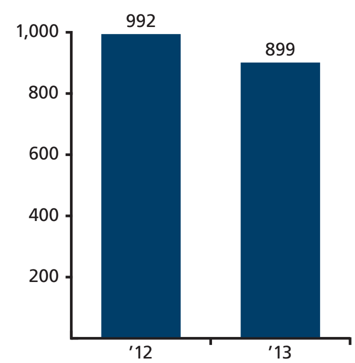
The table below outlines the Corporation's sources and uses of cash in 2013 compared to 2012, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows

Years Ended December 31

($ millions)	2013	2012	Variance
Cash, Beginning of Year	**154**	87	67
Cash Provided by (Used in):			
Operating Activities	**899**	992	(93)
Investing Activities	**(2,164)**	(1,096)	(1,068)
Financing Activities	**1,186**	171	1,015
Cash at Discontinued Operations	**(3)**	–	(3)
Cash, End of Year	**72**	154	(82)

Cash Flow from Operating Activities
($ millions)



Operating Activities: Cash flow from operating activities in 2013 was $93 million lower than in 2012. The decrease was primarily due to unfavourable changes in working capital and long-term regulatory deferral accounts at FortisAlberta. The decrease was partially offset by higher earnings and the collection from customers of regulator-approved increases in depreciation and amortization, and favourable changes in working capital at Maritime Electric.

Investing Activities: Cash used in investing activities in 2013 was $1,068 million higher than in 2012. The increase was mainly due to the acquisition of CH Energy Group in June 2013 for a net cash purchase price of $1,019 million and FortisBC Electric's acquisition of the electrical utility assets from the City of Kelowna in March 2013 for approximately $55 million. Higher capital expenditures were mainly due to capital spending at Central Hudson, partially offset by lower capital spending at the non-regulated Waneta Expansion. The increase was partially offset by cash proceeds from the settlement of expropriation matters associated with the Exploits Partnership.

Financing Activities: Cash provided by financing activities in 2013 was $1,015 million higher than in 2012, driven by financing associated with the acquisition of CH Energy Group. The increase was primarily due to higher proceeds from the issuance of common shares, long-term debt, borrowings under committed credit facilities and preference shares. The increase was partially offset by the redemption of preference shares in July 2013, higher repayments of long-term debt and lower advances from non-controlling interests.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease and finance obligations, and net borrowings (repayments) under committed credit facilities for 2013 and 2012 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	2013	2012	Variance
Central Hudson	**49** (1)	–	49
FortisAlberta	**149** (2)	124 (3)	25
Newfoundland Power	**69** (4)	–	69
Caribbean Utilities	**51** (5)	–	51
Corporate	**335** (6)	–	335
Total	**653**	124	529

(1) Issued November and December 2013, 5-year US$30 million 2.45% and 15-year US$17 million 4.09% unsecured notes, respectively. The net proceeds were used to repay long-term debt and for general corporate purposes.

(2) Issued September 2013, 30-year $150 million 4.85% unsecured debentures. The net proceeds were used to repay credit facility borrowings, to fund capital expenditures and for general corporate purposes.

(3) Issued October 2012, 40-year $125 million 3.98% unsecured debentures. The net proceeds were used to repay credit facility borrowings, to fund capital expenditures and for general corporate purposes.

(4) Issued November 2013, 30-year $70 million 4.805% first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings, which were incurred to fund capital expenditures, and for general corporate purposes.

(5) Issued May 2013, 15-year US$10 million 3.34% and 20-year US$40 million 3.54% unsecured notes. The net proceeds were used to repay short-term borrowings and to fund capital expenditures.

(6) Issued October 2013, 10-year US$285 million 3.84% and 30-year US$40 million 5.08% unsecured notes. The net proceeds were used to repay a portion of the Corporation's US dollar-denominated credit facility borrowings incurred to initially finance a portion of the CH Energy Group acquisition.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations

Years Ended December 31 *($ millions)*	**2013**	2012	Variance
FortisBC Energy Companies	**(28)**	(20)	(8)
Central Hudson	**(50)**	–	(50)
FortisBC Electric	**(1)**	(16)	15
Newfoundland Power	**(5)**	(5)	–
Caribbean Utilities	**(20)**	(16)	(4)
Fortis Properties	**(65)**	(28)	(37)
Other	**(4)**	(3)	(1)
Total	**(173)**	(88)	(85)

Net Borrowings (Repayments) Under Committed Credit Facilities

Years Ended December 31 *($ millions)*	**2013**	2012	Variance
FortisAlberta	**20**	(29)	49
FortisBC Electric	**44**	26	18
Newfoundland Power	**(42)**	22	(64)
Corporate	**162**	52	110
Total	**184**	71	113

Borrowings under credit facilities by the utilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility. The borrowings under the Corporation's committed credit facility in 2013 were incurred to finance a portion of the acquisition of CH Energy Group, to support the construction of the Waneta Expansion and to finance an equity injection into FortisAlberta in support of energy infrastructure investment.

Advances of approximately $59 million for 2013 and $93 million for 2012 were received from non-controlling interests in the Waneta Partnership to finance capital spending related to the Waneta Expansion. In January 2012 advances of approximately $12 million were received from two First Nations bands, representing their 15% equity investment in the LNG storage facility on Vancouver Island.

Proceeds from the issuance of common shares were $596 million for 2013 compared to $24 million for 2012. The increase was primarily due to the issuance of 18.5 million common shares pursuant to the conversion of Subscription Receipts on closing of the acquisition of CH Energy Group in June 2013 for proceeds of approximately $567 million, net of after-tax expenses. The increase also reflects a higher number of common shares issued under the Corporation's Dividend Reinvestment and Employee Share Purchase Plans.

In July 2013 Fortis issued 10 million First Preference Shares, Series K for gross proceeds of $250 million. The net proceeds were used to redeem all of the Corporation's First Preference Shares, Series C in July 2013 for $125 million, to repay a portion of credit facility borrowings and for other general corporate purposes.

In November 2012 Fortis completed a $200 million public offering of 8 million First Preference Shares, Series J. The net proceeds were used to repay borrowings under the Corporation's committed credit facility, which borrowings were primarily incurred to support the construction of the Waneta Expansion, and for other general corporate purposes.

Common share dividends paid in 2013 totalled $181 million, net of $70 million of dividends reinvested, compared to $170 million, net of $58 million of dividends reinvested, paid in 2012. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.24 in 2013 compared to $1.20 in 2012. The weighted average number of common shares outstanding was 202.5 million for 2013 compared to 190.0 million for 2012.

Contractual Obligations

The Corporation's consolidated contractual obligations with external third parties in each of the next five years and for periods thereafter, as at December 31, 2013, are outlined in the following table.

Contractual Obligations

As at December 31, 2013 *($ millions)*	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Long-term debt	**7,204**	780	103	360	79	344	5,538
Interest obligations on long-term debt	**7,298**	402	363	348	322	317	5,546
Government loan obligations (1)	**15**	–	10	5	–	–	–
Capital lease and finance obligations (2)	**2,369**	46	46	47	48	76	2,106
Gas purchase contract obligations (3)	**444**	312	66	18	16	11	21
Power purchase obligations							
Central Hudson (4)	**40**	10	6	6	6	3	9
FortisBC Electric (5)	**30**	13	9	5	3	–	–
FortisOntario (6)	**309**	48	50	51	52	53	55
Maritime Electric (7)	**102**	40	40	8	1	1	12
Capital cost (8)	**542**	21	19	21	19	21	441
Operating lease obligations (9)	**30**	6	5	5	5	5	4
Waneta Partnership promissory note (10)	**72**	–	–	–	–	–	72
Joint-use asset and shared service agreements (11)	**53**	3	3	3	3	2	39
Defined benefit pension funding contributions (12)	**77**	42	20	12	–	–	3
Performance Share Unit ("PSU") Plan obligations (13)	**8**	2	2	4	–	–	–
Other (14)	**7**	3	–	–	–	–	4
Total	**18,600**	1,728	742	893	554	833	13,850

(1) In prior years, FEVI received non-interest bearing repayable loans from the Government of Canada and the Government of British Columbia of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. As the loans are repaid and replaced with non-government debt financing, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure. At December 31, 2013, $10 million of the government loan payable is included in the current portion of long-term debt.

(2) Includes principal payments, imputed interest and executory costs, mainly related to FortisBC Electric's Brilliant PPA and Brilliant Terminal Station.

(3) Gas purchase contract obligations include various gas purchase contracts at the FortisBC Energy companies and Central Hudson. At the FortisBC Energy companies the obligations include the gross cash payments associated with natural gas derivatives and are based on market prices that vary with gas indices and reflect index prices that were in effect as at December 31, 2013. At Central Hudson the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2013.

(4) Central Hudson must acquire sufficient peak load capacity to meet the peak load requirements of its full-service customers. This capacity requirement is met through contracts with capacity providers, purchases from the New York Independent System Operator ("NYISO") capacity market and the Company's own generating capacity.

In November 2013 Central Hudson entered into a contract to purchase 200 MW of installed capacity from May 1, 2014 through April 30, 2017. The NYISO has been authorized by FERC to create a new capacity zone in the Lower Hudson Valley, to maintain system reliability and attract investments in new and existing generation, which is expected to be implemented in May 2014. The key terms of the contract provide that Central Hudson will pay the settlement price in the NYISO Capacity Spot Market auction for the relevant month of delivery minus US$0.175 per kilowatt-month, times the contract quantity of the product delivered during the month. Due to uncertainties associated with finalization of the new capacity zone and future capacity prices by the NYISO, the amounts associated with this contract cannot be reasonably determined and estimated at this time and are not included in the Contractual Obligations table above.

(5) Power purchase obligations for FortisBC Electric are comprised of a PPA with BC Hydro, a capacity agreement with Powerex Corp. ("Powerex"), and a capacity and energy purchase agreement with Brilliant Expansion Power Corporation ("Brilliant Corporation").

In May 2013 FortisBC Electric entered into a new PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013. This new PPA does not change the basic parameters of the BC Hydro PPA that expired on September 30, 2013. An executed version of the PPA was submitted by BC Hydro to the BCUC in May 2013 and is pending regulatory approval. In the interim period until the new PPA is approved by the BCUC, FortisBC Electric and BC Hydro have agreed to continue under the terms of the expired BC Hydro PPA. Power purchases in the interim are approved for recovery in customer rates. The power purchases from the new PPA are expected to be recovered in customer rates. The amounts associated with the new PPA have not been included in the Contractual Obligations table, pending review and approval by the BCUC.

In 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity through to February 2016 from Powerex, a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC Electric brings any new resources, such as capital or contractual projects, online prior to the expiry of the agreement, FortisBC Electric may terminate the contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex. The capacity being purchased under the agreement does not relate to a specific plant.

In November 2012 FortisBC Electric entered into an agreement to purchase capacity and energy from January 2013 through December 2017 from CPC acting on behalf of Brilliant Corporation. The capacity and energy being purchased under this agreement do not constitute a significant portion of the output of a specific plant. The agreement was accepted by the BCUC in December 2012.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"). The WECA allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. In May 2012 the WECA was accepted for filing as an energy supply contract by the BCUC. Amounts associated with the WECA have not been included in the Contractual Obligations table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

In 2013 FortisBC Electric entered into various agreements to purchase fixed-price winter capacity and energy purchases through 2015. The purchases under these agreements do not relate to specific plants.

(6) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of energy and capacity. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(7) Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In 2010 the Company signed a five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The contract includes fixed pricing for the entire five-year period. The other take-or-pay contract, which is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States, expires in November 2032.

(8) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit. A major refurbishment of Point Lepreau that began in 2008 was completed and the facility returned to service in November 2012. The refurbishment is expected to extend the facility's estimated life for an additional 27 years.

(9) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases.

(10) Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion. The amount disclosed is on a gross cash flow basis. The promissory note was recorded in long-term other liabilities at its discounted net present value of $50 million as at December 31, 2013.

(11) FortisAlberta and an Alberta transmission service provider have entered into an agreement to allow for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission system. Due to the unlimited term of this agreement, the calculation of future payments after 2018 includes payments to the end of 20 years. However, payments under this agreement may continue for an indefinite period of time.

FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. In the fourth quarter of 2013, FortisAlberta withdrew its notice to terminate these agreements and reinstated the minimum expiry terms of five years from September 1, 2010, subject to extension based on mutually agreeable terms.

(12) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2013 and 2015 – FortisBC Energy companies (plans covering non-unionized employees)
December 31, 2013 – FortisBC Energy companies (plan covering unionized employees)
December 31, 2013 – FortisBC Electric
December 31, 2014 – Newfoundland Power

As a result of the December 2011 actuarial valuation completed at Newfoundland Power in April 2012, the Company is required to fund a solvency deficiency of approximately $53 million, including interest, over five years which began in 2012 and is reflected in the Contractual Obligations table. The defined benefit pension funding contributions, including current service and solvency deficit funding amounts, are expected to be $14 million in 2014. The increase in funding contributions is expected to be recovered from customers in future rates.

(13) The settlement of PSUs outstanding as at December 31, 2013, which were granted in each of 2011, 2012 and 2013, is subject to the satisfaction of payment criteria over the three-year vesting periods by senior management of the Corporation and its subsidiaries, including the President and Chief Executive Officer ("CEO") of Fortis.

The Corporation's $6 million liability related to outstanding Directors' Deferred Share Units as at December 31, 2013 has been excluded from the Contractual Obligations table, as the timing of the payments is indeterminable at this time.

(14) Other contractual obligations mainly include building operating leases and AROs.

Other Contractual Obligations

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $1.4 billion for 2014. Over the five years 2014 through 2018, the Corporation's consolidated capital expenditure program, excluding capital spending at UNS Energy, is expected to exceed $6.5 billion, which has not been included in the Contractual Obligations table.

Pending Acquisition: In December 2013 Fortis entered into an agreement and plan of merger to acquire UNS Energy for US$60.25 per common share in cash, representing an aggregate purchase price of approximately US$4.3 billion, including the assumption of approximately US$1.8 billion of debt on closing. The agreement and plan of merger may be terminated by the Corporation or UNS Energy at any time prior to closing in certain circumstances, including if the acquisition has not closed by December 11, 2014, provided, however, that if the only unsatisfied conditions to closing are the obtaining of the regulatory approvals as defined in the agreement and plan of merger, then such date shall be extended to June 11, 2015. For further information on the pending acquisition of UNS Energy, refer to the "Significant Items – Pending Acquisition of UNS Energy" section of this MD&A.

Convertible Debentures Represented by Installment Receipts: To finance a portion of the pending acquisition of UNS Energy, in January 2014 Fortis, through a direct wholly owned subsidiary, completed the sale of $1.8 billion aggregate principal amount of 4% Debentures. For further information, refer to the "Significant Items – Convertible Debentures Represented by Installment Receipts" section of this MD&A.

Other: In 2012 Caribbean Utilities entered into primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2014 is 18.9 million imperial gallons. The contracts expire in July 2014 with the option to renew for two additional 18-month terms. The renewal options can be exercised only within six months of the expiry dates of the existing contracts.

FortisTCI has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $902 million as at December 31, 2013 have been excluded from the Contractual Obligations table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination, or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 7 to the Corporation's 2013 Annual Consolidated Financial Statements.

The FortisBC Energy companies have issued commitments to customers to provide EEC and NGV funding under the respective programs approved by the BCUC. As at December 31, 2013, approximately $24 million of funding had been committed to customers.

Capital Structure

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 45% equity, including preference shares, and 55% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure

	2013		2012	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [(1)]	**7,716**	**56.2**	6,317	55.3
Preference shares	**1,229**	**9.0**	1,108	9.7
Common shareholders' equity	**4,772**	**34.8**	3,992	35.0
Total [(2)]	**13,717**	**100.0**	11,417	100.0

(1) Includes long-term debt and capital lease and finance obligations, including current portion, and short-term borrowings, net of cash
(2) Excludes amounts related to non-controlling interests

The change in the capital structure was primarily due to the financing of the acquisition of CH Energy Group, including: (i) the conversion of Subscription Receipts into common shares for $567 million, net of after-tax expenses; (ii) debt assumed upon acquisition; (iii) the Corporation's US$325 million unsecured notes offering in October 2013 to finance a portion of the acquisition; and (iv) borrowings under the Corporation's committed credit facility to finance the remainder of the acquisition. The capital structure was also impacted by: (i) an increase in total debt, mainly in support of energy infrastructure investment; (ii) the issuance of First Preference Shares, Series K, partially offset by the redemption of First Preference Shares, Series C; (iii) net earnings attributable to common equity shareholders for the year ended December 31, 2013, less dividends declared on common shares; (iv) the issuance of common shares under the Corporation's Dividend Reinvestment Plan; and (v) a decrease in cash.

Excluding capital lease and finance obligations, the Corporation's capital structure as at December 31, 2013 was 54.9% debt, 9.2% preference shares and 35.9% common shareholders' equity (December 31, 2012 – 53.6% debt, 10.1% preference shares and 36.3% common shareholders' equity).

Credit Ratings

As at December 31, 2013, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A– / Negative (long-term corporate and unsecured debt credit rating)
DBRS	A(low) / Under Review – Developing Implications (unsecured debt credit rating)

The above-noted credit ratings reflect the Corporation's business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining low levels of debt at the holding company level. In December 2013, after the announcement by Fortis that it had entered into an agreement to acquire UNS Energy, DBRS placed the Corporation's credit rating under review with developing implications. Similarly, S&P revised its outlook on the Corporation to negative from stable. S&P indicated that an outlook revision to stable would likely occur when the Debentures are converted to equity.

Capital Expenditure Program

Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $110 million in maintenance and repairs was expensed in 2013 compared to approximately $103 million in 2012.

Gross consolidated capital expenditures for 2013 were approximately $1.2 billion. A breakdown of gross consolidated capital expenditures by segment and asset category for 2013 is provided in the following table.

Gross Consolidated Capital Expenditures [(1)]

Year Ended December 31, 2013

($ millions)	FortisBC Energy Companies	Central Hudson	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities – Canadian	Regulated Electric Utilities – Caribbean	**Total Regulated Utilities**	**Non-Regulated – Fortis Generation**	**Non-Regulated – Non-Utility** [(2)]	**Total**
Generation	–	–	–	2	6	2	25	**35**	**146**	**–**	**181**
Transmission	37	13	–	16	7	7	–	**80**	**–**	**–**	**80**
Distribution	131	32	282	23	68	42	17	**595**	**–**	**–**	**595**
Facilities, equipment, vehicles and other	23	9	135	22	6	3	8	**206**	**–**	**59**	**265**
Information technology	24	3	12	6	5	2	2	**54**	**–**	**–**	**54**
Total	215	57	429	69	92	56	52	**970**	**146**	**59**	**1,175**

(1) Relates to cash payments to acquire or construct utility capital assets, non-utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of the allowance for funds used during construction ("AFUDC").

(2) Includes capital expenditures of approximately $13 million at FAES, which is reported in the Corporate and Other segment

Gross consolidated capital expenditures of $1,175 million for 2013 were $155 million lower than $1,330 million forecast for 2013, as disclosed in the MD&A for the year ended December 31, 2012. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from those forecast. The decrease is primarily due to lower capital spending at the non-regulated Waneta Expansion, FortisBC Electric, FAES and Fortis Properties, partially offset by Central Hudson.

Lower capital expenditures related to the Waneta Expansion for 2013 are primarily due to the timing of payments. Capital expenditures at FortisBC Electric were lower than forecast for 2013 as a result of the slowdown of capital work due to labour disruptions, which ended in the fourth quarter. Due to the uncertainty of the timing of alternative energy projects at FAES, capital expenditures for 2013 were delayed and are lower than the original forecast. Capital expenditures at Fortis Properties for 2013 are lower than forecast due to the timing of capital projects, with a shift of more capital spending to 2014. Capital expenditures for 2013 include $57 million at Central Hudson from the date of acquisition, which were not included in the original 2013 forecast.

Gross consolidated capital expenditures for 2014 are expected to be approximately $1.4 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2014 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures [(1)]

Year Ending December 31, 2014

($ millions)	FortisBC Energy Companies	Central Hudson	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities – Canadian	Regulated Electric Utilities – Caribbean	**Total Regulated Utilities**	**Non-Regulated – Fortis Generation**	**Non-Regulated – Non-Utility** [(2)]	**Total**
Generation	–	1	–	7	11	2	36	**57**	**131**	**–**	**188**
Transmission	38	36	–	38	6	12	1	**131**	**–**	**–**	**131**
Distribution	134	57	289	42	81	36	16	**655**	**–**	**–**	**655**
Facilities, equipment, vehicles and other	136	19	109	37	3	3	6	**313**	**–**	**83**	**396**
Information technology	21	9	15	6	4	3	2	**60**	**–**	**–**	**60**
Total	329	122	413	130	105	56	61	**1,216**	**131**	**83**	**1,430**

(1) Relates to forecast cash payments to acquire or construct utility capital assets, non-utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC.

(2) Includes forecast capital expenditures of approximately $13 million at FAES, which is reported in the Corporate and Other segment

The percentage breakdown of 2013 actual and 2014 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows.

Gross Consolidated Capital Expenditures

Year Ending December 31 (%)	**Actual 2013**	Forecast 2014
Growth	**38**	33
Sustaining [(1)]	**35**	35
Other [(2)]	**27**	32
Total	**100**	100

(1) Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

(2) Relates to facilities, equipment, vehicles, information technology systems and other assets, including AESO transmission-related capital expenditures at FortisAlberta

Over the five-year period 2014 through 2018, gross consolidated capital expenditures, excluding capital spending at UNS Energy, are expected to exceed $6.5 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 50% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 27% at Canadian Regulated Gas Utilities; 11% at Central Hudson; 5% at Caribbean Regulated Electric Utilities; and the remaining 7% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 37% to meet customer growth; 46% to ensure continued and enhanced performance, reliability and safety of generation and T&D assets, i.e., sustaining capital expenditures; and 17% for facilities, equipment, vehicles, information technology and other assets.

UNS Energy has forecast that its capital expenditures will total approximately $1.5 billion (US$1.4 billion) over the period 2015 through 2018.

Forecast 2014 midyear rate base for the Corporation's largest regulated utilities is provided in the following table.

Forecast Midyear Rate Base

($ billions)	**2014**
FortisBC Energy Companies	**3.7**
Central Hudson	**1.1**
FortisAlberta	**2.5**
FortisBC Electric	**1.2**
Newfoundland Power	**1.0**

Significant capital projects for 2013 and 2014 are summarized in the table below.

Significant Capital Projects [(1)]

($ millions) Company	Nature of Project	Pre-2013	**Actual 2013**	Forecast 2014	Forecast Post-2014	Expected Year of Completion
FortisBC Energy Companies	Tilbury LNG Facility Expansion	–	**5**	100	295	2016
FortisAlberta	Pole-Management Program	117	**22**	29	185	2018
Waneta Partnership	Waneta Expansion [(2)]	436	**143**	126	105	2015

(1) Relates to utility capital asset, non-utility capital asset and intangible asset expenditures combined with both the capitalized interest and equity components of AFUDC, where applicable

(2) Includes the $72 million payment expected to be made in 2020 and excludes forecast capitalized interest of the minority partners, CPC/CBT, in the Waneta Partnership

FEI has begun the expansion of the Tilbury LNG facility. In November 2013 the Government of British Columbia announced the exemption of the Tilbury LNG facility expansion from a CPCN review by the BCUC. The expansion is expected to include a second LNG tank and a new liquefier, both to be in service in 2016. The expansion will increase LNG production and storage capabilities. The Tilbury LNG facility expansion is subject to additional regulatory and environmental permits and approvals. The Government of British Columbia imposed an upper limit of $400 million for project costs associated with the expansion, with approximately $100 million expected to be spent in 2014.

During 2013 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program, which involves approximately 110,000 poles in total, to prevent risk of failure due to age. The total capital cost of the program through 2018 is expected to be approximately $353 million. Approximately $22 million was spent on this program in 2013, for a total of $139 million to date.

Construction of the $900 million Waneta Expansion is ongoing, with an additional $143 million invested in 2013. Fortis owns a 51% interest in the Waneta Partnership and will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015. Key construction activities in 2013 included the substantial completion of civil construction of the powerhouse and tailrace structure; significant progress on the intake structure; installation of the turbine components, ancillary mechanical and electrical powerhouse services; and encapsulating of the scrollcase in concrete. During 2013, the generator step-up transformers and the first turbine runner were received on site for assembly and installation. The key offsite activity in 2013 was the successful completion of the manufacturing of the first turbine runner and turbine operating mechanism.

Approximately $579 million in total has been spent on the Waneta Expansion since construction began in late 2010, with approximately $126 million expected to be spent in 2014. Key project activities scheduled for 2014 include energization of the 230-kilovolt transmission line; completion of civil construction work; installation and assembly of the major components of the first and second turbine/generator units; installation of protection and control systems; and testing and commissioning. The first unit marketable power test is forecast to be completed in the fourth quarter of 2014.

The capital cost of the Waneta Expansion, as reported in the Significant Capital Projects table, includes capitalized interest during construction by Fortis, as well as other eligible capitalized expenses and a $72 million payment expected to be made in 2020 related to accrued development costs previously incurred by CPC/CBT. The table excludes approximately $50 million of forecast capitalized interest of the minority partners in the Waneta Partnership.

The Waneta Expansion is included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, and associated capacity required to deliver such energy for the Waneta Expansion will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, will be sold to FortisBC Electric under a long-term capacity purchase agreement.

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flows available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt offerings.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis.

Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends.

The subsidiaries expect to be able to source the cash required to fund their 2014 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be $780 million in 2014 and to average approximately $335 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments beyond 2014 will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

In July 2013 FortisBC Electric filed a short-form base shelf prospectus to establish a Medium-Term Note ("MTN") Debenture Program and entered into a dealer agreement with certain affiliates of a group of Canadian chartered banks. Upon filing the shelf prospectus, the Company may, from time to time during the 25-month life of the base shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $300 million. The establishment of the MTN Debentures Program has been approved by the BCUC.

In October 2013 FortisAlberta filed a short-form base shelf prospectus under which the Company may, from time to time during the 25-month life of the base shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $500 million.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2013 and are expected to remain compliant in 2014.

Credit Facilities

As at December 31, 2013, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.7 billion, of which approximately $2.2 billion was unused, including $785 million unused under the Corporation's $1 billion committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.6 billion of the total credit facilities are committed facilities with maturities ranging from 2014 through 2018.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities *($ millions)*	Regulated Utilities	Non-Regulated	Corporate and Other	**Total as at December 31, 2013**	Total as at December 31, 2012
Total credit facilities	1,546	119	1,030	**2,695**	2,460
Credit facilities utilized:					
Short-term borrowings	(157)	(3)	–	**(160)**	(136)
Long-term debt (including current portion)	(99)	–	(214)	**(313)**	(150)
Letters of credit outstanding	(65)	–	(1)	**(66)**	(67)
Credit facilities unused	1,225	116	815	**2,156**	2,107

As at December 31, 2013 and 2012, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Significant changes in credit facilities from December 31, 2012 to December 31, 2013 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2013 are detailed in Note 34 to the Corporation's 2013 Audited Consolidated Financial Statements.

As at December 31, 2013, CH Energy Group had a US$100 million ($106 million) unsecured revolving credit facility maturing in October 2015, and Central Hudson had a US$150 million ($159 million) unsecured committed revolving credit facility maturing in October 2016.

In 2013 FEI, FEVI, FortisAlberta and FortisBC Electric amended their committed revolving credit facilities, resulting in extensions to the maturity dates. Also, in 2013 the Corporation extended its $1 billion committed revolving corporate credit facility to mature in July 2018 from July 2015. The new agreements contain substantially similar terms and conditions as the previous credit facility agreements.

The credit facilities in the table above do not include the $2 billion non-revolving bridge credit facilities associated with the pending acquisition of UNS Energy.

In January 2014, as a result of closing the Debentures related to the pending acquisition of UNS Energy, Fortis agreed that until such time as the Debentures have been redeemed or the Final Installment Date has occurred, the Corporation will at all times maintain availability under its $1 billion committed revolving corporate credit facility of not less than $600 million to cover the principal amount of the first installment of the Debentures in the event of a mandatory redemption.

For further information regarding acquisition financing, refer to the "Significant Items" section of this MD&A.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $66 million as at December 31, 2013 (December 31, 2012 – $67 million), the Corporation had no off-balance sheet arrangements, such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities, that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to regulation that can affect future revenue and earnings.

The utilities are subject to uncertainties faced by regulated entities, including approval by the respective regulatory authorities of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated COS, including a fair rate of return on rate base and, in the case of utilities in the Caribbean, the continuation of licences. Generally, the ability of a utility to recover the actual COS and earn the approved ROE and/or ROA depends on achieving the forecasts established in the rate-setting process. Gas and electricity infrastructure investments require the approval of the regulatory authorities either through the approval of capital expenditure plans or revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or COS. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved. Capital cost overruns may not be recoverable in customer rates.

Regulators approve the allowed ROEs and deemed capital structures. Fair regulatory treatment that allows a utility to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining service quality, as well as ongoing capital attraction and growth.

Rate applications establishing revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through a litigated public hearing process. There can be no assurance that resulting rate orders issued by the regulators will permit the regulated utilities to recover all costs actually incurred and to earn the expected or fair rates of return on an appropriate capitalization.

A failure to obtain acceptable rate orders, appropriate ROEs or capital structures as applied for may adversely affect the business carried on by the regulated utilities, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the issuance of long-term debt and other matters, which may, in turn, have a material adverse effect on the results of operations and financial position of the Corporation's regulated utilities. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Approximately 93% of the Corporation's operating revenue(1) was derived from regulated utility operations in 2013 (2012 – 93%), while approximately 87% of the Corporation's operating earnings(1) were derived from regulated utility operations in 2013 (2012 – 90%). Regulated utility assets comprised approximately 90% of total assets of Fortis as at December 31, 2013 (December 31, 2012 – 90%). Fortis considers the regulatory frameworks in North America to be fair and balanced. There is, however, a concentration of regulatory risk in British Columbia, with 47% of the Corporation's regulated assets under the jurisdiction of the BCUC. The risk is heightened by a significant regulatory calendar for the FortisBC gas and electricity businesses. The FortisBC utilities will be busy through the first half of 2014 with various filings, interrogatories, inquiries and/or hearings occurring, including those related to the second stage of the GCOC Proceeding and the applications for Multi-Year PBR Plans for 2014 through 2018.

Significant regulatory uncertainty remains at FortisAlberta associated with PBR, effective January 1, 2013, as well as the final approval of the Company's 2013 Capital Tracker Application. FortisAlberta's final allowed ROE and capital structure for 2013 and 2014 also remain to be determined, subject to the outcome of the GCOC Proceeding initiated by the AUC in 2013. In early 2014 FortisAlberta will re-file its Capital Tracker Application in accordance with the prescribed format issued by the AUC in December 2013. Currently, it is unknown whether the new approach will alter the Company's applied for 2013 capital tracker amount and, in the interim, FortisAlberta has been directed to retain the placeholder of 60% of the applied for capital tracker amount, as approved in the Interim Compliance Decision. A decision on the 2013 Capital Tracker Application is expected by the end of 2014.

During the PBR term, FortisAlberta is exposed to risks related to the PBR formula, specifically that: (i) the Company will experience inflationary increases in excess of the inflationary factor set by the AUC; (ii) the Company will be unable to achieve the productivity improvements expected over the PBR term; (iii) the costs related to FortisAlberta's capital expenditures will be in excess of those provided for in the base formula and excess capital expenditures will not qualify, or be approved, as a capital tracker; and (iv) material unforeseen costs will be incurred that will not qualify or be approved.

The AUC has indicated a preference to employ generic proceedings to address regulatory matters that impact multiple utilities. While generic proceedings allow for regulatory efficiencies, there is the risk of favouring a collective result regardless of individual utility circumstances.

(1) Operating revenue and operating earnings are non-US GAAP measures and refer to total revenue excluding Corporate and Other segment revenue and inter-segment eliminations, and net earnings attributable to common equity shareholders excluding Corporate and Other segment expenses, respectively. Operating revenue and operating earnings are referred to by users of the consolidated financial statements in evaluating the performance of the Corporation's operating subsidiaries.

As an owner of an electricity distribution network under the *Electric Utilities Act* (Alberta), FortisAlberta is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as a default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, FortisAlberta appointed EPCOR Energy Services (Alberta) Inc. ("EPCOR") as its regulated-rate provider. As a result of this appointment, EPCOR assumed all of FortisAlberta's rights and obligations in respect of these services. In the unlikely event that EPCOR is unable or unwilling to act as a regulated-rate provider or default supplier, and no other party is willing to act in this capacity, FortisAlberta would be required to act as a provider of electricity services to eligible customers under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If FortisAlberta could not secure outsourcing for these functions, it would need to administer these retail responsibilities by adding necessary staff, facilities and/or equipment.

Most of the Corporation's regulated utilities are not currently subject to AAMs to set allowed ROEs. Generally, AAMs use a formula that calculates an annual adjustment to allowed ROEs based upon changes in the long-term Government of Canada bond yields. As part of the first stage of the GCOC Proceeding in British Columbia, the BCUC introduced an AAM at FEI to set the allowed ROE for the benchmark utility on an annual basis, effective January 1, 2014 through December 31, 2015. The AAM will take effect when the long-term Government of Canada bond yield exceeds 3.8%. The allowed ROEs for 2013 are currently being reviewed by the regulators in Alberta and British Columbia, and uncertainty exists as to whether AAMs will be re-established and what the final allowed ROEs and capital structures will be. For FEVI, FEWI and FortisBC Electric, the final allowed ROEs and capital structures for 2013 and 2014 are subject to the outcome of the second stage of the GCOC Proceeding, which is expected in the first half of 2014. A regulatory decision on the Multi-Year PBR Applications, filed by the FortisBC Energy companies and FortisBC Electric in 2013, is expected in the third quarter of 2014.

For additional information on the nature of regulation and various regulatory matters pertaining to the Corporation's utilities, refer to the "Regulatory Highlights" section of this MD&A.

Political Risk: The regulatory framework under which utilities operate is impacted by significant shifts in government policy and/or changes in governments, which create uncertainty about public policy priorities and directions, particularly around energy and environmental issues.

Completion of the Acquisition of UNS Energy: The closing of the acquisition of UNS Energy is subject to normal commercial risks that the acquisition will not close on the terms negotiated, or at all. The pending acquisition remains subject to receipt of UNS Energy shareholder approval and satisfaction of other approval conditions, including the approval of the ACC and FERC, and the satisfaction or waiver of certain closing conditions contained in the agreement and plan of merger. The failure to obtain the required approvals or satisfy or waive the conditions may result in the termination of the agreement and plan of merger and the failure to materialize some, or all, of the expected benefits of the acquisition within the time periods anticipated by the Corporation. The realization of such benefits may also be impacted by other factors beyond the control of Fortis. If the closing of the acquisition of UNS Energy does not take place as contemplated, the Corporation could suffer adverse consequences, including the loss of investor confidence.

A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Corporation's ability to complete the acquisition and on the Corporation's or UNS Energy's business, financial condition or results of operations. Fortis intends to complete the acquisition as soon as practicable after obtaining the required UNS Energy shareholder approval and regulatory approvals, and satisfying the other required closing conditions. Failure to realize the anticipated benefits of the acquisition of UNS Energy may impact the financial performance of the Corporation, the price of its common shares and the ability of Fortis to continue to pay dividends on its common shares.

For the purpose of financing the acquisition, the Corporation completed the $1.8 billion Debenture Offering in January 2014 and obtained a commitment letter for an aggregate of $2 billion non-revolving term credit facilities. For further information, refer to the "Significant Items" section of this MD&A. The commitment of the lenders to enter into these credit facilities is subject to certain standard conditions, which may result in such facilities becoming unavailable to Fortis in certain circumstances. If these credit facilities become unavailable, Fortis may not be able to complete the acquisition.

If a material amount of the final installment is not paid by holders of Debentures and the Corporation is not able to quickly realize on the Debentures pledged to secure the obligation to pay the final installment, the Corporation will not be able to use those proceeds to finance a portion of the acquisition price. As a result, Fortis may be required to draw down additional funds under the $2 billion non-revolving term credit facilities and it may take Fortis longer than anticipated to repay these credit facilities. This may have a negative impact on the consolidated capitalization of Fortis until such time as the credit facilities have been repaid by Fortis in full.

Failure to obtain sufficient financing at acceptable terms and cost through the Offerings, the $2 billion non-revolving term credit facilities, the Corporation's available corporate committed credit facilities or other long-term financing could result in additional financing costs, the termination of the agreement and plan of merger and the failure to materialize some, or all, of the expected benefits of the acquisition.

Fortis is exposed to foreign exchange risk associated with the acquisition of UNS Energy as the cash consideration for the acquisition is required to be paid in US dollars, while funds raised in the Debenture offering, which will constitute a significant portion of the funds used to finance the acquisition, are denominated in Canadian dollars. As a result, increases in the US dollar-to-Canadian dollar exchange rate prior to payment of the Final Installment will increase the purchase price translated in Canadian dollars, and thereby reduce the proportion of the purchase price for the acquisition ultimately obtained by Fortis under the Debenture offering. In addition, the operations of UNS Energy are conducted in US dollars and, following the acquisition, the consolidated earnings and cash flows of Fortis will be impacted to a greater extent by fluctuations in the US dollar-to-Canadian dollar exchange rate. For further discussion on foreign exchange risk, refer to the "Business Risk Management – Derivative Instruments and Hedging" section of this MD&A.

Fortis also expects to incur a number of costs associated with completing the acquisition. The majority of these costs will be non-recurring expenses and will consist of transaction costs related to the acquisition, including costs related to financing and obtaining regulatory approval. Additional unanticipated costs may be incurred in 2014 related to the acquisition.

Interest Rate Risk: Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs directly when they are applied in formulaic ROE AAMs or indirectly through a regulatory process of what constitutes an appropriate rate of return on investment, which may consider the general level of interest rates. Uncertainty exists regarding the duration of the current environment of low interest rates and what effect it may have on allowed ROEs of the Corporation's regulated utilities. A significant decline in interest rates and the resulting impact on the allowed ROEs could adversely affect the financial condition and results of operations of the Corporation's regulated utilities. Also, if interest rates begin to climb, regulatory lag may cause a delay in any resulting increase in cost of capital and the regulatory allowed ROEs.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with borrowings under variable-rate credit facilities and the refinancing of long-term debt. At the FortisBC Energy companies, interest expense variances from forecast for rate-setting purposes related to short-term and long-term interest rates and the timing of long-term debt issuances are recovered through future rates using regulator-approved deferral mechanisms. There can be no assurance that such deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions. Central Hudson also has regulatory approval to defer any increase or decrease in interest rate expense, resulting from fluctuations in interest rates associated with variable-rate credit facilities, for recovery from, or refund to, customers in future rates. At the Corporation's other regulated utilities, if the timing of issuance of, and the interest rates on, long-term debt are different from those forecast and approved in customer rates, the additional or lower interest costs incurred on the new long-term debt are not recovered from, or refunded to, customers in rates during the period that was covered by the approved customer rates. An inability to flow through interest costs to customers could have a material adverse effect on the results of operations and financial position of the utilities.

Excluding borrowings under long-term committed credit facilities, approximately 80% of the Corporation's consolidated long-term debt as at December 31, 2013 had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2013.

Total Debt

As at December 31, 2013	*($ millions)*	*(%)*
Short-term borrowings	**160**	**2.2**
Utilized variable-rate credit facilities classified as long term	**313**	**4.2**
Variable-rate long-term debt (including current portion)	**51**	**0.7**
Fixed-rate long-term debt (including current portion)	**6,840**	**92.9**
Total	**7,364**	**100.0**

In 2013 long-term debt was issued at the Corporation and certain of its regulated utilities at rates ranging from 2.45% to 5.08% and with terms ranging from 5 to 30 years, demonstrating the ability of the utilities to raise long-term capital at attractive rates. Further information on the Corporation's consolidated long-term debt issuances is provided in the "Liquidity and Capital Resources" section of this MD&A.

A change in the level of interest rates could materially affect the measurement and disclosure of the fair value of long-term debt. The fair value of the Corporation's consolidated long-term debt, as at December 31, 2013, is provided in the "Financial Instruments" section of this MD&A.

Operating and Maintenance Risks: Storms, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the Corporation's utilities could result in service disruptions, leading to lower earnings and/or cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery. The FortisBC Energy companies and Central Hudson are exposed to various operational risks such as: pipeline leaks; accidental damage to mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas that could result in significant operational disruptions and/or environmental liability. The business of electricity T&D is also subject to operational risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. In addition, a significant portion of the utilities' infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged. The FortisBC utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and other acts of nature. The FortisBC Energy companies, FortisBC Electric and the Corporation's operations in the Caribbean region are subject to risk of loss from earthquakes. The Corporation and its subsidiaries have limited insurance that provides coverage for business interruption, liability and property damage. In the event of a large uninsured loss caused by severe weather conditions, natural disasters and certain other events beyond the control of the utility, an application would be made to the respective regulatory authority for the recovery of these costs through higher customer rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. Refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

The Corporation's gas and electricity systems require ongoing maintenance, improvement and replacement. The utilities could experience service disruptions and increased costs if they are unable to maintain their asset base. The inability to recover, through approved customer rates, the expenditures the utilities believe are necessary to maintain, improve, replace and remove assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material adverse effect on the financial position and results of operations of the Corporation's utilities.

Generally, the Corporation's utilities have designed their natural gas and electricity systems to service customers under various contingencies in accordance with good utility practice. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, processes and/or procedures to ensure the safety of employees and contractors, as well as the general public. Failure to do so may disrupt the ability of the utilities to safely distribute gas and electricity, which could have a material adverse effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. Management's analysis is based on assumptions as to COS and equipment, regulatory requirements, revenue requirement approvals and other matters, which involve some degree of uncertainty. If actual costs exceed regulator-approved capital expenditures, it is uncertain whether any additional costs will receive regulatory approval for recovery in future customer rates. It is generally expected, however, that prudently incurred costs can be recovered in customer rates. The inability to recover additional costs, however, could have a material adverse effect on the utilities' financial position and results of operations. Refer also to the "Business Risk Management – Regulatory Risk" section of this MD&A.

Economic Conditions: Typical of utilities, economic conditions, such as changes in employment levels, personal disposable income, energy prices and housing starts, in the Corporation's service territories influence energy sales. The FortisBC Energy companies are also affected by the trend in housing starts from single-family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. The growth in new multi-family housing starts continues to significantly outpace that of new single-family homes, which may temper growth in gas distribution volumes.

Generally, higher energy prices can result in reduced consumption by customers. However, natural gas and crude oil exploration and production activities in certain of the Corporation's service territories are closely correlated with natural gas and crude oil prices. The level of these activities, which tend to increase with increased energy prices, can influence energy demand, affecting local energy sales in some of the Corporation's service territories.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time that could reduce capital spending and, in turn, affect rate base and earnings growth. The regulated nature of utility operations, including various mitigating measures approved by regulators, helps reduce the impact that lower energy demand associated with poor economic conditions may have on the utilities' earnings. However, a severe and prolonged downturn in economic conditions could materially affect the utilities' performance despite regulatory measures available to compensate for reduced demand. In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for the gas and electricity they consume, thereby affecting the aging and collection of the utilities' trade receivables.

The Corporation's service territory in the Caribbean region continues to be impacted by challenging economic conditions despite moderate signs of recovery in 2013. Assets of Caribbean Regulated Electric Utilities comprise approximately 5% of the Corporation's total assets. Activity in the tourism, real estate and construction sectors is closely tied to economic conditions in the region and changes in such activity affect customer electricity demand. Electricity sales at Caribbean Utilities and Fortis Turks and Caicos are expected to increase 2% and 5%, respectively, in 2014, reflecting the completion of certain specific local development projects in the region in 2014.

Fortis also holds investments in both commercial office and retail space and hotel properties, with these assets combined representing approximately 4% of the Corporation's total assets. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. The Canadian hospitality industry continues to recover from the economic downturn at a slow rate. Approximately 58% of Fortis Properties' operating income was derived from hotel investments in 2013 (2012 – 57%). It is estimated that a 10% decrease in revenue in Fortis Properties' Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents. The Canadian commercial real estate industry demonstrated continued stability in 2013. Over the next five years, Fortis Properties' real estate exposure to lease expiries is expected to average approximately 12% per annum. Growth expected in the Real Estate Division will be driven by increasing rates in St. John's as a result of strong market conditions and the expected completion of a new office building in St. John's in mid-2014.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it and/or its larger subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation and its subsidiaries; the regulatory environment in which the utilities operate and the nature and outcome of regulatory decisions regarding capital structure and allowed ROEs; conditions in the capital and bank credit markets; ratings assigned by credit rating agencies; and general economic conditions. Funds generated from operations after payment of expected expenses, including interest payments on any outstanding debt, may not be sufficient to fund the repayment of all outstanding liabilities when due and anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and repay existing debt.

Consolidated long-term debt maturities in 2014 are expected to total $780 million. The ability to meet long-term debt repayments when due will be dependent on the Corporation and its subsidiaries obtaining sufficient and cost-effective financing. The Corporation and its utilities have been successful at raising long-term capital at reasonable rates. Activity in the global capital markets may impact the cost and timing of issuance of long-term capital by the Corporation and its subsidiaries. While the future cost of raising capital could increase, the Corporation and its subsidiaries expect to continue to have reasonable access to capital in the near to medium terms.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. As at December 31, 2013, Fortis had approximately $2.7 billion in consolidated credit facilities, of which $2.6 billion is committed with maturities ranging from 2014 through 2018. Approximately $2.2 billion of the consolidated credit facilities was unused as at December 31, 2013. Approximately $215 million was drawn on the committed corporate credit facility at as December 31, 2013. In January 2014, as a result of closing the Debentures related to the pending acquisition of UNS Energy, Fortis agreed that until such time as the Debentures have been redeemed or the Final Installment Date has occurred, the Corporation will at all times maintain availability under its $1 billion committed revolving corporate credit facility of not less than $600 million to cover the principal amount of the first installment of the Debentures in the event of a mandatory redemption.

The cost of renewed and extended credit facilities could increase going forward; however, any increase in interest expense and fees is not expected to materially impact the Corporation's consolidated financial results in 2014. Due to their regulated nature, any forecast changes in the cost of borrowing at the utilities are eligible to be reflected in customer rates. During 2013 various credit facilities were renegotiated and amended, resulting in extensions to the maturity dates. The new agreements contain substantially similar terms and conditions as the previous agreements.

Generally, the Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt and credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term.

In 2013, the following changes were made to the credit ratings of the Corporation's utilities. In February 2013 S&P updated Maritime Electric's debt credit rating from 'A– stable' to 'A stable'. In June 2013 Moody's Investors Service ("Moody's") affirmed the long-term credit ratings of FHI, FEI, FEVI and FortisBC Electric, and changed the rating outlooks to negative from stable. In July 2013 Fitch Ratings and Moody's affirmed Central Hudson's debt credit ratings at 'A stable' and 'A3 stable', respectively, and S&P also affirmed the Company's debt credit rating at 'A' and removed it from 'credit watch with negative implications'. In December 2013, after the announcement by Fortis that it had entered into an agreement to acquire UNS Energy, DBRS placed the Corporation's credit rating under review with developing implications. Similarly, S&P revised its outlook on the Corporation, FortisAlberta, Maritime Electric and Caribbean Utilities to negative from stable. In January 2014 Moody's upgraded Central Hudson to 'A2' from 'A3' with a stable outlook, reflecting a more favourable view of the relative credit supportiveness of the U.S. regulatory environment. In February 2014 DBRS confirmed FortisAlberta's credit rating at 'A(low)' and changed the trend to positive from stable, reflecting the Company's strong financial metrics.

Additional information on the Corporation's consolidated credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A.

Expropriation of Shares in Belize Electricity: On June 20, 2011, the GOB enacted in one day the *Electricity (Amendment) Act 2011* ("Acquisition Act") and the *Electricity (Assumption of Control over Belize Electricity Limited) Order 2011* ("*Acquisition Order*") to expropriate the Corporation's majority ownership investment in Belize Electricity but did not expropriate any of the minority ownership investments, which continue to be held by the Social Security Board of Belize and Belizean residents. The purported public purpose stated in the *Acquisition Order* as the basis for the decision to expropriate Belize Electricity was "*to maintain an uninterrupted and reliable supply of electricity to the public*". The Corporation's evidence is that there was no risk of interruption or unreliable electricity supply at the time of expropriation and, while Belize Electricity had financial difficulties in 2011, such difficulties were caused by the GOB and, therefore, the GOB cannot rely on a situation it created to justify expropriating Belize Electricity.

Four days after expropriation of the Corporation's investment in Belize Electricity, the Belize Court of Appeal delivered its judgment that a similar expropriation of control of Belize Telemedia Limited ("Belize Telemedia"), a public telecommunications provider in Belize, in 2009 was unconstitutional, null and void. Rather than accept and appeal the judgment, the GOB enacted revised expropriation legislation to retain control of Belize Telemedia and contemporaneously proposed a constitutional amendment, the purported effect of which was to: (i) declare the GOB's ownership of three specifically identified public utility providers, including Belize Electricity and Belize Telemedia; (ii) deem the expropriation of Belize Electricity and re-expropriation of Belize Telemedia to have been done for a public purpose; and (iii) oust the jurisdiction of the Belize Courts to review the GOB expropriation actions.

On October 21, 2011, Fortis filed a claim ("Claim No. 673 of 2011") in the Belize Supreme Court challenging the GOB's expropriation of the Corporation's investment in Belize Electricity pursuant to the *Acquisition Act* and *Acquisition Order*. On October 25, 2011, the *Belize Constitution (Eighth Amendment) Act 2011* ("*Eighth Amendment*") was enacted to validate and immunize the GOB's expropriation of Belize Electricity and Belize Telemedia. As a consequence of the above, Fortis subsequently amended its Claim No. 673 of 2011 to additionally challenge the constitutionality of the *Eighth Amendment*.

On June 11, 2012, the trial division of the Belize Supreme Court delivered its judgment in the claims of *British Caribbean Bank Limited v Attorney General et al* ("Claim No. 597 of 2011") and *Dean Boyce v Attorney General et al* ("Claim No. 646 of 2011") (collectively the "Telemedia Judgment") regarding the purported re-expropriation of Belize Telemedia. The court determined that the re-expropriation of the Claimants' properties by the GOB in those claims was unconstitutional, null and void. The judge determined most of the *Eighth Amendment* to be invalid, but found that he could sever those portions of sections 143 and 144 of the *Eighth Amendment* which declare GOB ownership of the named utilities, and that the severance thereby prevented the judge from ordering divestiture of the GOB's control of Belize Telemedia and hence the judge found himself precluded by the Belize Constitution from granting the Claimants the consequential relief sought.

Hearing of the Corporation's Claim No. 673 of 2011 occurred on July 2, 2012 before the same judge who delivered the Telemedia Judgment. The judge believed he was bound by his reasons in the Telemedia Judgment and dismissed the Corporation's Claim No. 673 of 2011 on the grounds that the severed portions of the *Eighth Amendment* precluded divestiture of the GOB's ownership and control of Belize Electricity, notwithstanding the *Acquisition Act* and *Acquisition Order*, which are virtually identical to the provisions of the 2009 expropriation of Belize Telemedia, and were found to be invalid by the Belize Court of Appeal. The judge, therefore, denied the relief sought by Fortis.

On July 5, 2012, Fortis filed its appeal of the above-noted July 2, 2012 trial judgment to the Belize Court of Appeal. The Belize Court of Appeal allowed an application for consolidation of the Corporation's appeal with the appeal and cross-appeal of the Telemedia Judgment, and directed that the appeals be heard on an expedited basis commencing October 8, 2012.

In its appeal, Fortis submitted that the *Acquisition Act* violates the Belize Constitution and should be struck down as: (i) the *Acquisition Act* does not prescribe the principles and manner in which reasonable compensation is to be determined in a reasonable time; (ii) the *Acquisition Act* does not provide a right of access to the Belize Court for the purpose of enforcing a right to compensation; and (iii) certain sections of the *Acquisition Act* violate certain sections of the Belize Constitution. Fortis also submitted that the *Acquisition Order* violates the Corporation's constitutional rights and should be struck down as: (i) it is not proportionate; (ii) the expropriation of Belize Electricity by the GOB was arbitrary as the GOB did not acquire the minority shareholdings of the Social Security Board or Belizean nationals in Belize Electricity and is, therefore, in violation of the Belize Constitution; and (iii) Fortis was not afforded a right to be heard by the Belize Minister of Public Utilities before its property was compulsorily acquired by the GOB. Fortis also contends that the application of saved portions of sections 143 and 144 of the *Eighth Amendment* are also invalid and should not have precluded the ordering of consequential relief to Fortis for several reasons, including the fact that such provisions are void as they: (a) deprive the Belize Court of jurisdiction to conduct the constitutionally mandated inquiry to determine a person's interest or right in property compulsorily acquired, whether such acquisition was for a public purpose, the amount of compensation to which a person is entitled and for enforcement of a person's right to any such compensation; (b) are in breach of the principle of equality before the law and the rule of law; and (c) on their own do not fulfill the intention of the legislature of the Belize Government and are inextricably bound up with the legislation ruled to be unconstitutional in the Telemedia Judgment.

The consolidated appeal hearing occurred from October 8 to October 10, 2012. However, since one of the judges on the panel was the subject of a complaint to the Belize Judicial Council by parties to the Telemedia Judgment, an application for disqualification of that judge was made and subsequently denied by a majority of the appeal panel. In December 2012 the Caribbean Court of Justice ("CCJ") entertained an application for special leave to appeal the above-noted majority decision denying the disqualification of the judge in question. During argument of the application, the CCJ accepted that the decision not to disqualify the judge could become grounds for appeal of the judgment of the Belize Court of Appeal and, as a result, the special leave to appeal was withdrawn by the applicants.

Counsel for the GOB admitted during the October 2012 consolidated appeal hearing that the *Acquisition Act* and *Acquisition Order* were contrary to the laws of Belize as they now stand, on the basis of the Belize Court of Appeal decision regarding the 2009 expropriation of Belize Telemedia, but that the severed provisions of the *Eighth Amendment* preclude the return of majority control over Belize Electricity to Fortis. The decision of the Belize Court of Appeal is pending. Any decision of the Belize Court of Appeal may be appealed to the CCJ, the highest court of appeal available for judicial matters in Belize.

Consequent to the deprivation of control over the operations of Belize Electricity, the Corporation discontinued the consolidation method of accounting for the utility, as of June 20, 2011, and classified the book value, including foreign exchange impacts, of the expropriated investment as a long-term other asset on the consolidated balance sheet. As at December 31, 2013, the long-term other asset, including foreign exchange impacts, totalled $108 million (December 31, 2012 – $104 million). Fortis commissioned an independent valuation of its expropriated investment and submitted its claim for compensation to the GOB in November 2011. The book value of the long-term other asset is below fair value as at the date of expropriation as determined by the independent valuators. The GOB also commissioned a valuation of Belize Electricity, which is significantly lower than both the fair value determined under the Corporation's valuation and the book value of the long-term other asset. While Fortis, GOB representatives and third-party consultants to the GOB held discussions in 2012 on differences in assumptions used in the valuations, there have been no discussions on any compensation settlement amount.

Fortis believes it has a strong, well-positioned case before the Belize Courts supporting the unconstitutionality of the expropriation. There exists, however, a possibility that the outcome of the litigation may be unfavourable to the Corporation and the amount of compensation otherwise to be paid to Fortis under the legislation expropriating Belize Electricity could be lower than the book value of the Corporation's expropriated investment in Belize Electricity. If the expropriation is held to be unconstitutional, it is not determinable at this time as to the nature of the relief that would be awarded to Fortis; for example: (i) ordering return of the shares to Fortis and/or award of damages; or (ii) ordering compensation to be paid to Fortis for the unconstitutional expropriation of the shares and/or award of damages. Based on presently available information, the $108 million long-term other asset is not deemed impaired as at December 31, 2013. Fortis will continue to assess for impairment each reporting period based on evaluating the outcomes of court proceedings and/or compensation settlement negotiations. As well as continuing the constitutional challenge of the expropriation, Fortis is also pursuing alternative options for obtaining fair compensation, including compensation under the Belize/United Kingdom Bilateral Investment Treaty.

Fortis continues to control and consolidate the financial statements of BECOL, the Corporation's indirect wholly owned non-regulated hydroelectric generating subsidiary in Belize. As at February 28, 2014, Belize Electricity owed BECOL US$1 million for overdue energy purchases. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

Information Technology and Cyber-Security Risks: The ability of the Corporation's utilities to operate effectively is dependent upon developing, managing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities, including the communication infrastructure and supporting systems necessary to provide important safety information to mobile devices for field staff; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business. While the utilities have various measures in place to protect their information systems against cyber-security incidents, there is no assurance that such incidents may not occur.

Cyber-security threats are continuously changing and require ongoing monitoring and detection capabilities. Unauthorized access to corporate and information technology systems due to hacking, viruses and other causes could result in service disruptions and system failures, which could have a material adverse effect on the utilities, such as the inability to provide energy to customers. In addition, in the normal course of operations, the Corporation's utilities and non-regulated subsidiaries require access to confidential customer data, including personal and credit information, which could be exposed in the event of a cyber-security incident.

The Corporation's subsidiaries have security measures and controls in place to protect corporate and information technology systems, and safeguard the confidentiality of customer information. Despite the existence of these security measures and controls, a cyber-security incident could result in service disruptions, property damage, corruption or unauthorized access to critical data or confidential customer information, lower earnings and/or cash flows, fines and other penalties, reputational damage and increased regulation and litigation, all of which could impact the Corporation's results of operations if the situation is not resolved in a timely manner, or if the financial impacts are not alleviated through insurance policies or, in the case of regulated utilities, through regulatory recovery.

Capital Project Budget Overrun, Completion and Financing Risk in the Corporation's Non-Regulated Business: In its non-regulated business, Fortis generally bears the risk of budget overruns on capital projects, including increased costs associated with higher financing expense, schedule delays and lower-than-expected performance. Budget overruns, when incurred prudently in the regulated business, can generally be recovered in customer rates as part of COS. The risk of cost overruns is mitigated by contractual approach, regular and proactive monitoring by employees with appropriate expertise and regular review by senior management. Cost overruns and delays in project completion may also occur when unforeseen circumstances arise. The construction of the non-regulated Waneta Expansion remains on time and within budget with completion expected in spring 2015.

Weather and Seasonality Risk: The physical assets of the Corporation and its subsidiaries could be exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. Regulatory deferral mechanisms are in place at certain of the Corporation's regulated utilities, including the FortisBC Energy companies, FortisBC Electric, Central Hudson and Newfoundland Power, to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence of the above-noted regulatory deferral mechanisms could have a material adverse effect on the results of operations and financial position of the utilities.

At the FortisBC Energy companies and Central Hudson, weather has a significant impact on distribution volume as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas-consumption patterns, the gas utilities normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. The earnings of the regulated gas utilities are highest in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. In Canada and New York State cool summers may reduce air conditioning demand, while less severe winters may reduce electric heating load. In the Caribbean the impact of seasonal changes in weather on air conditioning demand is less pronounced due to the less variable seasonal changes that exist in the region; however, higher- or lower-than-normal temperatures can have a significant impact on air conditioning demand. Significant fluctuations in weather-related demand for electricity could materially impact the operations, financial condition and results of operations of the electric utilities.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River, where FortisBC Electric's dams and related facilities are located, in order to protect the environment. This adjustment could affect the amount of water available for generation at FortisBC Electric's plants or at plants operated by parties contracted to supply energy to FortisBC Electric. FortisBC Electric's entitlement to capacity and energy under the Canal Plant Agreement may be reduced if climate change in the future leads to a significant and sustained loss of precipitation over the entire headwaters of the Kootenay River system. To have an effect on the entitlements of capacity and energy, such change would likely have to persist for a prolonged period.

Despite preparations for severe weather, hurricanes and other natural disasters will always remain a risk to utilities. Climate change, however, may have the effect of increasing the severity and frequency of weather-related natural disasters that could affect the Corporation's service territories.

The assets and earnings of Caribbean Utilities, Fortis Turks and Caicos and, to a lesser extent, Central Hudson, Newfoundland Power and Maritime Electric are subject to hurricane risk. The Corporation's utilities may also be subject to severe weather events, including ice, wind and snow storms. Weather risks are managed through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. Under its T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster such as a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost-recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant weather event. Central Hudson is authorized to request, and the PSC has typically approved, deferral account treatment for incremental storm restoration costs. To qualify for deferral, storm costs must meet certain criteria as stipulated by the PSC. In most cases, the Corporation's other regulated utilities can apply to their respective regulators for relief from major uncontrollable expenses, including those related to significant weather-related events.

Earnings from non-regulated generation assets are sensitive to rainfall levels. The Waneta Expansion is included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing the hydrologic risk associated with hydroelectric generation.

Commodity Price Risk: The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. Central Hudson is exposed to commodity price risk associated with changes in the market prices of electricity and natural gas. The operation of regulator-approved deferral mechanisms to flow through in customer rates the cost of natural gas and electricity serves to mitigate the impact on earnings of commodity price volatility. The risks have also been reduced by entering into natural gas and electricity derivatives that effectively fix the price of natural gas and electricity purchases, respectively. The FortisBC Energy companies employ various price risk-management strategies to reduce exposure to commodity rates charged to customers due to natural gas price volatility. However, as ordered by the BCUC, the FortisBC Energy companies discontinued most hedging activities, with existing hedges being managed to expiry. The absence of such hedging tools results in an increased exposure by customers to market price volatility. At Central Hudson electricity swap contracts and natural gas derivatives are used to minimize commodity price volatility for the Company's full-service customers by fixing the effective purchase price for the defined commodities. The absence of such hedging mechanism in the future could result in increased exposure to market price volatility.

Certain of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affect the cost of fuel and purchased power. The risk is substantially mitigated by the utilities' ability to flow through to customers the cost of fuel and purchased power through base rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel and purchased power will continue to exist in the future. Also, a severe and prolonged increase in such costs could materially affect the FortisBC Energy companies and Central Hudson, despite regulatory measures available to compensate for changes in these costs. The inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could have a material adverse effect on the utilities' results of operations and financial position.

Derivative Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates, and fuel, electricity and natural gas prices through the use of derivative instruments. The Corporation does not hold or issue derivative instruments for trading purposes and generally limits the use of derivative instruments to those that qualify as accounting or economic hedges. As at December 31, 2013, the Corporation's derivative instruments primarily consisted of electricity swap contracts, gas swap and option contracts, and gas purchase contract premiums.

Mark-to-market is the default accounting treatment for all derivative instruments unless they qualify, and are designated, for one of the elective accounting treatments. Mark-to-market requires the derivative instrument to be recorded at fair value with changes in fair value recognized in earnings.

Electricity swap contracts are held by Central Hudson. Gas swap and option contracts, and gas purchase contract premiums are held by the FortisBC Energy companies and Central Hudson. Any difference between the amount recognized upon a change in the fair value of a derivative instrument and the amount recovered from customers in current rates is subject to regulatory deferral account treatment to be recovered from, or refunded to, customers in future rates.

The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Central Hudson, Caribbean Utilities, Fortis Turks and Caicos, BECOL, FortisUS Energy and Griffith is the US dollar.

As at December 31, 2013, the Corporation's corporately issued US$1,033 million (December 31, 2012 – US$557 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at December 31, 2013, the Corporation had approximately US$560 million (December 31, 2012 – US$17 million) in foreign net investments remaining to be hedged. Both the Corporation's US dollar-denominated long-term debt and foreign net investments as at December 31, 2013 were significantly impacted by the CH Energy Group acquisition. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity are recognized in earnings. In 2013 the Corporation recognized in earnings a foreign exchange gain of approximately $6 million (2012 – a foreign exchange loss of approximately $2 million).

It is estimated that a 5 cent, or 5%, increase or decrease in the US dollar-to-Canadian dollar exchange rate from the exchange rate of US$1.00=CDN$1.0636 as at December 31, 2013 would increase or decrease basic earnings per common share of Fortis by approximately 1 cent in 2014, before considering the impact of the pending acquisition of the UNS Energy.

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: The FortisBC Energy companies and Central Hudson may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The FortisBC Energy companies and Central Hudson deal with reasonable credit-quality institutions in accordance with established credit approval practices. These utilities did not experience any counterparty defaults in 2013 and do not expect any counterparties to fail to meet their obligations.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its gross exposure associated with retailer billings by obtaining from the retailer either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

Competitiveness of Natural Gas: Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, since the majority of electricity prices in British Columbia were set based on the historical average cost of production, primarily associated with hydroelectric generation rather than based on market forces, the competitive advantage of natural gas was substantially eroded during the decade that followed. More recently, there has been upward pressure on electricity rates in British Columbia, largely due to new investment required in the electricity generation and transmission sectors. In addition, the growth in North American natural gas supply, primarily from shale gas production, has resulted in a lower natural gas price environment. These factors have helped to improve natural gas competitiveness on an operating basis. Nevertheless, differences in upfront capital costs between electric and natural gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of natural gas on a full-cost basis. Going forward, a decrease in growth of natural gas production due to low market prices, increased demand due to industrial growth, coal-plant retirements and the potential for LNG exports are factors that may lead to materially higher market gas prices and increased price volatility. These have the potential to impact natural gas competitiveness over the longer term.

Government policy has also impacted the competitiveness and perception of the benefits of natural gas in British Columbia. In 2008 the Government of British Columbia introduced changes to energy policy, including GHG emission reduction targets and a consumption tax on carbon-based fuels. It did not, however, introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes in energy policy may have a material impact on the competitiveness of natural gas relative to non-carbon-based energy sources or other energy sources.

There are other competitive challenges impacting the penetration of natural gas in new housing supply, such as the green attributes of the energy source and the type of housing being built. In recent years, the FortisBC Energy companies have experienced a decline in the percentage of new homes installing natural gas compared with the total number of dwellings being built throughout British Columbia.

In the future, if natural gas becomes less competitive due to pricing or other factors, the ability of the FortisBC Energy companies to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. The above conditions may result in higher customer rates and, in an extreme case, could ultimately lead to an inability of the FortisBC Energy companies to fully recover COS in rates charged to customers.

Refer also to the "Business Risk Management – Risks Related to FEVI" and "Environmental Risks" sections of this MD&A.

Natural Gas, Fuel and Electricity Supply: The FortisBC Energy companies are dependent on a limited selection of pipeline and storage providers, particularly in the Lower Mainland, Interior and Vancouver Island service areas. Regional market prices, particularly at the Sumas market hub, have been higher than prices elsewhere in North America during peak winter periods, when regional pipeline and storage resources become constrained in serving the demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, the FortisBC Energy companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the FortisBC Energy companies could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers. The LNG storage facility on Vancouver Island helps to reduce this risk by providing short-term on-system supply during cold weather conditions or emergency situations.

Developments are occurring in the region that may increase the demand for gas supply from British Columbia. These include an increase in pipeline capacity to deliver gas from British Columbia to markets outside of British Columbia and the potential development of large-scale LNG facilities to export gas to Asian markets. As British Columbia has significant natural gas resources, it is uncertain at this time what effect this increase in demand could have on regional market prices.

Newfoundland Power is dependent on Newfoundland and Labrador Hydro ("Newfoundland Hydro") for approximately 93% of its customers' energy requirements and Maritime Electric is dependent on NB Power for over 80% of its customers' energy requirements. In addition, the Caribbean utilities are dependent on third parties for the supply of all of their fuel requirements in the operation of their diesel-powered generating facilities. A shortage or interruption of the supply of electricity or fuel for the above utilities could have a material impact on their operations.

In January 2013 and January 2014, Newfoundland Power experienced a loss of electricity supply from Newfoundland Hydro, which interrupted customer power supply and resulted in significant outages. In January 2014 the Government of Newfoundland and Labrador ordered an independent review of the electricity system in the province and the PUB indicated it would also conduct an inquiry and hearing into the system supply issues and power interruptions experienced in the province in early 2014. To the extent it is able, Newfoundland Power will participate in these proceedings in 2014.

Future changes in supply costs at Newfoundland Power, including costs associated with Nalcor Energy's Muskrat Falls hydroelectric generation development and associated transmission assets, may affect electricity prices in a manner that affects the Company's sales.

Power Supply and Capacity Purchase Contracts: FortisBC Electric's indirect customers are directly served by the Company's wholesale customers, who themselves are municipal utilities. The municipal utilities may be able to obtain alternate sources of energy supply, which would result in decreased demand, higher customer rates and, in an extreme case, could ultimately lead to an inability by FortisBC Electric to fully recover its COS in rates charged to customers.

Additionally, the Corporation's regulated electric utilities periodically enter into various power supply and capacity purchase contracts with third and/or related parties. Upon expiry of the contracts, there is a risk that the utilities may not be able to secure extensions of such contracts and, if the contracts are not extended, there is a risk of the utilities not being able to obtain alternate supplies of similarly priced electricity. The utilities are also exposed to power supply availability risk in the event of non-performance by counterparties to the various power supply and capacity contracts. In 2013 FortisBC Electric and BC Hydro entered into a new PPA, effective October 2013, to replace the BC Hydro PPA that expired in September 2013. Regulatory approval of the new PPA is pending; however, the terms of the expired PPA will continue in the interim and power purchase costs are approved for recovery in customer rates, which is expected to continue on approval of the new PPA.

FortisBC Electric has a power supply sale agreement with BC Hydro for the sale of electricity generated from its non-regulated Walden hydroelectric generating facility, which had a net book value of approximately $10 million as at December 31, 2013. Subject to a five-month notice of termination by BC Hydro, which has not yet been issued, this agreement could expire. Accordingly, the Company is exposed to the risk that it will not be able to sell the power from this facility in the future on similar terms.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of FHI, the FortisBC Energy companies, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, FortisOntario, Algoma Power, Caribbean Utilities and Fortis maintains defined benefit pension plans for certain of their employees. Approximately 59% of the above companies' total employees are members of such plans.

The defined benefit pension plans are subject to judgments utilized in the actuarial determination of the projected benefit obligation and related net pension cost. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the projected benefit obligation. For a discussion of the critical accounting estimates associated with defined benefit pension plans, refer to the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

Projected benefit obligations and related net pension cost can be affected by changes in the global financial and capital markets. There is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed long-term return on the assets, which may cause material changes in future pension funding requirements from current estimates and material changes in future net pension cost. Market-driven changes impacting the discount rates may also result in material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of net pension cost, future funding requirements and the projected benefit obligation.

The above-noted risks are mitigated as any increase or decrease in future pension funding requirements and/or net pension cost at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. However, at the FortisBC Energy companies, Central Hudson, FortisBC Electric and Newfoundland Power, actual net pension cost above or below forecast net pension cost approved for recovery in customer rates for the year is also subject to deferral account treatment, subject to regulatory approval. There can be no assurance that the current regulator-approved deferral mechanisms will continue to exist in the future. An inability to flow through net pension costs in customer rates could have a material adverse effect on the results of operations and financial position of the regulated utilities. Also mitigating the above-noted risks is the fact that the defined benefit pension plans at Central Hudson, FortisAlberta, Newfoundland Power and FortisOntario are closed to all new employees.

Risks Related to FEVI: FEVI operates in the price-competitive service area of Vancouver Island, with a customer base and revenue that are currently sufficient to meet the Company's COS. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement provided royalty revenue from the Government of British Columbia that covered approximately 20% of FEVI's COS. The royalty revenue expired at the end of 2011, after which FEVI's customers were required to absorb the full commodity cost of natural gas and all other COS. The Company also received approval from the BCUC in its 2012/2013 revenue requirements decision for the continuation of the Revenue Surplus Deferral Account mechanism, which continues to allow FEVI to recover costs from customers above FEVI's approved COS. Also, the remaining $25 million of outstanding non-interest-bearing government loans, which is currently treated as a government contribution against utility capital assets, is expected to be repaid by the end of 2016. As the debt is repaid, the higher rate base will increase COS and customer rates. With the cessation of royalty revenue and repayment of the government loans, the resultant increase in customer rates, as compared to electricity or alternative forms of energy, may make gas less competitive on Vancouver Island over time.

Environmental Risks: The Corporation's gas and electric utilities are subject to inherent risks, including fires, contamination of air, soil or water from hazardous substances, natural gas emissions and emissions from the combustion of fuel required in the generation of electricity. Risks associated with fire damage are related to weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims in connection with fires on land on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the transportation, handling and storage of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity, mainly at the Corporation's regulated utilities in the Caribbean. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances.

The management of GHG emissions is the main environmental concern of the Corporation's Regulated Gas Utilities in Canada, primarily due to the Government of British Columbia's Energy Plan, *Carbon Tax Act*, *Clean Energy Act*, *Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act*. The Energy Plan contains a strong focus on environmental leadership, energy conservation and efficiency, and investing in innovation. Many of the principles of the Energy Plan were incorporated into the regulatory framework in British Columbia upon the British Columbia Legislature passing the *Utilities Commission Amendment Act, 2008* and passing the *Clean Energy Act*. The *Clean Energy Act*, which establishes a long-term vision for the province as a leader in clean energy development, came into force in June 2010. FortisBC Electric and the FortisBC Energy companies continue to assess and monitor the impact the Energy Plan and the *Clean Energy Act* may have on future operations. Energy to be produced by the Waneta Expansion in British Columbia, upon its completion, is consistent with the objective under the *Clean Energy Act* to reduce GHG emissions. In 2011 the FortisBC Energy companies began reporting their GHG emissions pursuant to the reporting regulation under the *Greenhouse Gas Reduction (Cap and Trade) Act*. In addition, the FortisBC Energy companies continue to report their GHG emissions under Environment Canada's GHG Reporting Program. The FortisBC Energy companies have developed capabilities that will support the management of compliance requirements in an upcoming GHG emissions' trading environment, as government policy in that area evolves. The Companies will also continue to monitor and assess emerging regulations, in particular, the offset and allowance regulations.

The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol were extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Specific details of the regulations implementing the protocol have yet to be released by the local government of the Cayman Islands and, accordingly, Caribbean Utilities is currently unable to assess the financial impact of compliance with the framework of the protocol.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, and the requirement for environmental impact assessments and remediation work. It is possible that other developments may lead to increasingly strict environmental laws and enforcement policies, and claims for damages to property or persons resulting from the operations of the Corporation's subsidiaries, any one of which could result in substantial costs or liabilities to the subsidiaries.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by insurance. For further information, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs can arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment, and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines, or damages could become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. The Corporation believes that it and its subsidiaries are materially compliant with the environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate.

Central Hudson is exposed to environmental contingencies associated with manufactured gas plants ("MGPs") that it and its predecessors owned and operated to serve their customers' heating and lighting needs from the mid- to late 1800s to the 1950s. The New York State Department of Environmental Conservation ("DEC") regulates the timing and extent of remediation of MGP sites in New York State. As at December 31, 2013, Central Hudson has recognized approximately US$41 million in associated MGP environmental remediation liabilities. As approved by the PSC, the Company is currently permitted to recover MGP site investigation and remediation costs in customer rates.

With the exception of the MGP remediation liabilities at Central Hudson as noted above, as at December 31, 2013, there were no material environmental liabilities recognized in the Corporation's 2013 Audited Consolidated Financial Statements. Also, there were no material unrecorded environmental liabilities known to management, except for the possibility of liabilities associated with various contingencies as discussed in the "Critical Accounting Estimates – Contingencies" section of this MD&A. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could have a material adverse effect on the results of operations and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines, or their enforcement or regulatory interpretation, could materially impact the results of operations and financial position of the Corporation and its subsidiaries.

Each of the utilities of Fortis has an Environmental Management System ("EMS"), with the exception of Fortis Turks and Caicos, which expects to complete the implementation of its EMS by the end of 2014. Environmental policies form the cornerstone of the EMS and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regularly conduct environmental monitoring and audits of the EMS and strive for continual improvement in environmental performance; (v) regularly set and review environmental objectives, targets and programs; (vi) communicate openly with stakeholders, including making available the utility's environmental policy and knowledge of environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community-based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

During 2013 direct costs arising from environmental protection, compliance, damages and the carrying out of EMS responsibilities were not material to the Corporation's consolidated results of operations, cash flows or financial position. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable.

Insurance Coverage Risk: The Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their assets, for amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including practices of owners of similar assets and operations. However, a significant portion of the Corporation's regulated electric utilities' T&D assets is not covered under insurance, as is customary in North America, as the cost of coverage is not considered economically viable. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authority to recover the loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs, lost revenue and customer claims that are substantial in amount and which could have a material adverse effect on the Corporation's and subsidiaries' results of operations, cash flows and financial position. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's and subsidiaries' results of operations, cash flows and financial position.

It is anticipated that insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements, or that the insurance companies will meet their obligations to pay claims.

Loss of Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government, government agencies and First Nations bands. The Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval, or if there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation's subsidiaries.

FortisBC Electric's ability to generate electricity from its facilities on the Kootenay River and to receive its entitlement of capacity and energy under the Canal Plant Agreement depends upon the maintenance of its water licences issued under the *Water Act* (British Columbia). In addition, water flows on the Kootenay River are governed under the terms of the Columbia River Treaty between Canada and the United States, as well as the International Joint Commission's Order for Kootenay Lake. Government authorities in Canada and the United States have the power under the treaty and the International Joint Commission's Order to regulate water flows to protect environmental standards in a manner that could adversely affect the amount of water available for the generation of power.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, or in the absence, of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta), with the price to be as agreed by the Company and the municipality, failing which it is to be determined by the AUC. Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to the Company for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. This reduction of rate base could have a material adverse effect on the results of operations and financial position of FortisAlberta.

Continued Reporting in Accordance with US GAAP: In January 2014 the Ontario Securities Commission ("OSC") issued a relief order which permits the Corporation and its reporting issuer subsidiaries to continue to prepare their financial statements in accordance with US GAAP until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after the Corporation or its reporting issuer subsidiaries ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board ("IASB") for the mandatory application of a standard within International Financial Reporting Standards ("IFRS") specific to entities with activities subject to rate regulation. The OSC relief order effectively replaces and extends the OSC's previous relief order, which was due to expire effective January 1, 2015.

If the OSC relief does not continue as detailed above, the Corporation and its reporting issuer subsidiaries would then be required to become U.S. Securities and Exchange Commission issuers in order to continue reporting under US GAAP, or adopt IFRS. The IASB has recently released an interim, optional standard on Regulatory Deferral Accounts and continues to work on a project focusing on accounting specific to rate-regulated activities. It is not yet known when this project will be completed or whether IFRS will, as a result, include a permanent, mandatory standard to be applied by entities with activities subject to rate regulation. In the absence of a permanent standard for rate-regulated activities, the application of IFRS at that time could result in volatility in the Corporation's earnings and earnings per common share as compared to those which would otherwise be recognized under US GAAP.

Changes in Tax Legislation: In June 2013 Canada enacted legislation relating to the taxation of multinationals, which included new rules, originally proposed on August 19, 2011, relating to upstream loans and a new regime for the repatriation of capital. This new legislation also enacted tax rates to be used for Part VI.1 tax deductions. For further information on Part VI.1 tax, refer to the "Significant Items – Part VI.1 Tax" section of this MD&A.

Upstream Loans: The Corporation has approximately $61 million of upstream loans from its Caribbean subsidiaries. Fortis used these upstream interest-free loans as a tax-deferred repatriation of earnings. The new legislation requires that these loans be repaid within two years or be included in income of the parent. The new legislation also provided a special transition rule for loans that were in place on or before August 19, 2011 and states that, if such upstream loans remain outstanding on August 19, 2014, they are deemed to have arisen on August 19, 2014. These loans must then be repaid within two years of that day, being August 19, 2016, in order to avoid an income inclusion by Fortis for the 2014 taxation year. All of the Corporation's upstream loans were in place on August 19, 2011 and qualify for the special transition rule.

Repatriation of Capital: The new legislation also introduces changes in how earnings can be repatriated to Canada. Earnings are divided into four categories: exempt surplus, taxable surplus, hybrid surplus and pre-acquisition surplus. Historically, earnings were repatriated first from exempt surplus, then taxable surplus and finally pre-acquisition surplus. The new legislation will allow taxpayers to elect which surplus account to use for any repatriation of earnings. However, Canada requires the governments of these tax-free jurisdictions to enter into tax treaties or other comprehensive Tax Information Exchange Agreements ("TIEAs") to access the repatriation rules. Once in force, the TIEAs will permit dividends paid out of active business income to be exempted from tax when received in Canada. Also, the change in the ordering rules will allow Fortis to receive a tax-free return of capital from the Caribbean. These changes provide a mechanism to repay these upstream loans, thereby allowing the Corporation to comply with the above legislative changes.

TIEAs are in place with the Cayman Islands, Bermuda and the Turks and Caicos Islands, and Fortis expects that the TIEA with Belize will be in place by the end of 2014. If Belize is unable to establish a TIEA with Canada, earnings of BECOL will be taxed on an accrual basis as if they were earned in Canada.

The Corporation has made representations to the Government of Canada to reconsider businesses such as Fortis, which have active business income in offshore jurisdictions, and to structure the rules to continue to exempt businesses such as utilities. Fortis is also consulting with tax advisors to determine restructuring alternatives and other actions it can take to minimize the income tax impacts of the new measures in jurisdictions where a TIEA is not in force.

Any future changes in other tax legislation could also materially affect the Corporation's consolidated earnings.

Access to First Nations' Lands: The FortisBC Energy companies and FortisBC Electric provide service to customers on First Nations' lands and maintain gas facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the service areas of the FortisBC Energy companies and FortisBC Electric is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as the FortisBC Energy companies and FortisBC Electric. However, there can be no certainty that the settlement process will not have a material adverse effect on the FortisBC Energy companies' and FortisBC Electric's results of operations and financial position.

The Supreme Court of Canada decided in 2010 that, before issuing regulatory approvals for the addition of new facilities, the BCUC must consider whether the Crown has a duty to consult and accommodate First Nations, if necessary, and if so, whether the consultation and accommodation by the Crown have been adequate. This may affect the timing, cost and likelihood of the BCUC's approval of certain capital projects of the FortisBC Energy companies and FortisBC Electric.

FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual First Nations band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material adverse effect on FortisAlberta.

Labour Relations Risk: Approximately 57% of the employees of the Corporation's subsidiaries are members of labour unions or associations that have entered into collective bargaining agreements with the subsidiaries. The Corporation considers the relationships of its subsidiaries with their labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in the future or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material adverse effect on the results of operations, cash flows and financial position of the utilities.

The collective agreement between FortisBC Electric and International Brotherhood of Electrical Workers ("IBEW") expired on January 31, 2013. IBEW represents employees in specified occupations in the areas of generation and T&D. The parties commenced negotiations in January 2013, and in March 2013 the IBEW served the Corporation 72 hours' strike notice and commenced partial job action on May 16, 2013. The labour disruption ended in December 2013 when the IBEW and FortisBC Electric agreed to binding interest arbitration. The arbitration process is scheduled to occur over the first half of 2014.

The collective agreement between employees in specified occupations in the areas of administration and operations support at FortisBC Electric and Canadian Office and Professional Employees Union ("COPE") expired on December 31, 2013. A new five-year collective agreement, expiring on December 31, 2018, at FortisBC Electric came into effect in January 2014.

The collective agreements between customer service employees at the FortisBC Energy companies and FortisBC Electric, and COPE expire on March 31, 2014; however, the Companies have negotiated agreements with COPE, subject to ratification, that expire on March 31, 2017.

The two collective agreements between Newfoundland Power and IBEW expire on September 30, 2014.

Human Resources Risk: The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada, the United States and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and a competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

NEW ACCOUNTING POLICIES

The new US GAAP accounting policies that are applicable to, and were adopted by, Fortis, effective January 1, 2013, are described as follows.

Disclosures About Offsetting Assets and Liabilities: The Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 210, *Balance Sheet – Disclosures About Offsetting Assets and Liabilities* as outlined in Accounting Standards Update ("ASU") No. 2011-11 and ASU No. 2013-01. The amendments improve the transparency of the effect or potential effect of netting arrangements on a company's financial position by expanding the level of disclosures required by entities for such arrangements. The above-noted amendments were applied retrospectively and did not materially impact the Corporation's 2013 Audited Consolidated Financial Statements.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income: The Corporation adopted the amendments to ASC Topic 220, *Other Comprehensive Income – Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income* ("AOCI") as outlined in ASU No. 2013-02. The amendments improve the reporting of reclassifications out of AOCI and require entities to report, in one place, information about reclassifications out of AOCI and to present details of the reclassifications in the disclosure for changes in AOCI balances. The amendments were applied by the Corporation prospectively commencing on January 1, 2013 and did not materially impact the Corporation's 2013 Audited Consolidated Financial Statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

Obligations Resulting from Joint and Several Liability Arrangements: In February 2013 the Financial Accounting Standards Board ("FASB") issued ASU No. 2013-04, *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date*. The objective of this update is to provide 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. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied retrospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Parent's Accounting for the Cumulative Translation Adjustment: In March 2013 FASB issued ASU No. 2013-5, *Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity*. This update applies to the release of the cumulative translation adjustment into net earnings 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 within a foreign entity. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Presentation of an Unrecognized Tax Benefit: In July 2013 FASB issued ASU No. 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*. This amendment provides guidance on the presentation of unrecognized tax benefits when net operating loss carryforwards, similar tax losses or tax credit carryforwards exist, and is intended to better reflect the manner in which an entity would settle any additional income taxes that would result from the disallowance of a tax position when net operating loss carryforwards, similar tax losses or tax credit carryforwards exist. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

Financial Instruments

As at December 31	**2013**		2012	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**50**	**50**	47	51
Long-term debt, including current portion	**7,204**	**8,084**	5,900	7,338

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The Financial Instruments table above excludes the long-term other asset associated with the Corporation's expropriated investment in Belize Electricity. Due to uncertainty in the ultimate amount and ability of the GOB to pay appropriate fair value compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the book value of the expropriated investment, including foreign exchange impacts, in long-term other assets, which totalled approximately $108 million as at December 31, 2013 (December 31, 2012 – $104 million).

The following table summarizes the Corporation's derivative instruments.

Derivative Instruments

As at December 31	**2013**				2012
(Liability) Asset	**Maturity**	**Number of Contracts**	**Volume** (1)	**Carrying Value** (2) ***($ millions)***	Carrying Value (2) *($ millions)*
Fuel option contracts (3)	**2013**	**–**	**–**	**–**	(1)
Electricity swap contracts	**2017**	**7**	**3,313**	**10**	–
Natural gas derivatives:					
Gas swap and option contracts	**2014**	**29**	**6**	**(13)**	(51)
Gas purchase contract premiums	**2015**	**49**	**91**	**(2)**	(8)

(1) The volume for electricity swap contracts is reported in GWh and natural gas derivatives is reported in PJ.
(2) Carrying value is estimated fair value. The (liability) asset represents the gross derivatives balance.
(3) The fuel option contracts used by Caribbean Utilities matured in October 2013.

The electricity swap contracts and natural gas derivatives are used by Central Hudson to minimize commodity price volatility for electricity and natural gas purchases for the Company's full-service customers by fixing the effective purchase price for the defined commodities. The fair values of the electricity swap contracts and natural gas derivatives were calculated using forward pricing provided by independent third parties.

The natural gas derivatives are used by the FortisBC Energy companies to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, mitigate gas price volatility on customer rates and reduce the risk of regional price discrepancies. As directed by the regulator, the FortisBC Energy companies have suspended their commodity hedging activities, with the exception of certain limited swaps as permitted by the regulator. The existing hedging contracts will continue in effect through to their maturities and the FortisBC Energy companies' ability to fully recover the cost of gas in customer rates remains unchanged. Any differences between the cost of natural gas purchased and the price of natural gas included in customer rates are recorded as regulatory deferrals and are recovered from, or refunded to, customers in future rates, subject to regulatory approval. For further information refer to the "Business Risk Management – Commodity Price Risk" section of this MD&A.

The fair values of the electricity swap contracts and natural gas derivatives are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates. As at December 31, 2013, none of the electricity swap contracts and natural gas derivatives were designated as hedges of electricity and natural gas supply contracts.

The changes in the fair values of the electricity swap contracts and natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. The fair value of the electricity swap contracts is recorded in accounts receivable and other long-term assets and the fair value of the natural gas derivatives is recorded in accounts payable and other current liabilities as at December 31, 2013 and 2012.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known. The Corporation's critical accounting estimates are discussed as follows.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

As at December 31, 2013, Fortis recognized a total of $1,822 million in regulatory assets (December 31, 2012 – $1,700 million) and $1,042 million in regulatory liabilities (December 31, 2012 – $753 million).

For a further discussion of the nature of regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Depreciation and Amortization: Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2013, the Corporation's consolidated utility capital assets, non-utility capital assets and intangible assets were approximately $12.6 billion, or approximately 70%, of total consolidated assets compared to approximately $10.6 billion, or approximately 71%, of total consolidated assets as at December 31, 2012. The increase in capital assets was primarily due to the acquisition of CH Energy Group and capital expenditures, which totalled approximately $1.2 billion in 2013. Depreciation and amortization was $541 million for 2013 compared to $470 million for 2012. Changes in depreciation rates may have a significant impact on the Corporation's consolidated depreciation and amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate depreciation and amortization rates are approved by the respective regulatory authority. As required by their respective regulator, the FortisBC Energy companies, Central Hudson, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-ARO removal costs in depreciation with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. The estimate of non-ARO removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2013 was $563 million (December 31, 2012 – $486 million). The total amount of non-ARO removal costs accrued and recognized in depreciation expense during 2013 was $73 million (2012 – $42 million).

The depreciation periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over- or under-depreciation, as a result of actual experience differing from that expected and provided for in previous depreciation rates, is generally reflected in future depreciation rates and depreciation expense, when the differences are refunded or collected in customer rates as approved by the regulator.

Income Taxes: Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of deferred income taxes resulting from temporary differences between the carrying values of assets and liabilities in the consolidated financial statements and their tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Deferred income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recognized against earnings in the period when the allowance is created or revised. Estimates of the provision for current income taxes, deferred income tax assets and liabilities, and any related valuation allowance, might vary from actual amounts incurred.

Assessment for Impairment of Goodwill and Indefinite-Lived Intangible Assets: The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill and indefinite-lived intangible assets, and any impairment provision is charged to earnings. The annual impairment test is performed as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No such event or change in circumstances occurred during 2013 or 2012.

As at December 31, 2013, consolidated goodwill totalled approximately $2.1 billion (December 31, 2012 – $1.6 billion). As a result of closing the acquisitions of CH Energy Group by the Corporation and the electrical utility assets from the City of Kelowna by FortisBC Electric in 2013, additional goodwill of approximately $476 million and $14 million, respectively, was recognized. Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights and totalled approximately $66 million as at December 31, 2013 (December 31, 2012 – $66 million).

Fortis performs an annual internal quantitative assessment for each reporting unit and for those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as determined by an independent external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an independent external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an independent external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each reporting unit estimated by an independent external consultant once every three years.

In calculating goodwill impairment, Fortis determines those reporting units which will have fair value estimated by an independent external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, then a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, is also performed by an independent external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

No impairment provisions were required in either 2013 or 2012 with respect to goodwill or indefinite-lived intangible assets.

Employee Future Benefits: The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligation are the discount rate for the benefit obligation and the expected long-term rate of return on plan assets.

The expected weighted average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2014, is 6.34% which is up from 6.29% used in 2013. The defined benefit pension plan assets experienced total positive returns of approximately $124 million in 2013 compared to expected positive returns of $70 million. The expected long-term rates of return on pension plan assets are developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2013, and to determine net pension cost for 2014, is 4.76% compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2012, and to determine net pension cost for 2013, of 4.14%. The increase in the assumed weighted average discount rate reflects higher yields on investment-grade corporate bonds. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year.

There was a $14 million increase in consolidated defined benefit net pension cost for 2013 compared to 2012, mainly due to the acquisition of Central Hudson. Excluding Central Hudson, increased costs resulting from lower discount rates assumed and the amortization of actuarial losses were largely offset by an increase in estimated returns on plan assets, due to a higher asset base, and increased regulatory adjustments. Any increases in defined benefit net pension cost at the regulated utilities for 2014 are expected to be recovered from customers in rates, subject to forecast risk at those utilities with smaller defined benefit plans.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2013 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2013 Annual Consolidated Financial Statements.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2013

(Decrease) increase *($ millions)*	**Net pension benefit cost**	**Projected benefit obligation** [(1)]
Impact of increasing the rate of return assumption by 100 basis points	(3)	53
Impact of decreasing the rate of return assumption by 100 basis points	2	(49)
Impact of increasing the discount rate assumption by 100 basis points	(27)	(214)
Impact of decreasing the discount rate assumption by 100 basis points	30	264

[(1)] At the FortisBC Energy companies and FortisBC Electric, the methodology for determining the pension indexing assumption, which impacts the measurement of the projected benefit obligation, is based on the expected long-term rate of return on pension plan assets. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation. The direction of the impact of a change in the rate of return assumption at the FortisBC Energy companies and FortisBC Electric is also the result of the methodology for determining the pension indexing assumption.

Other assumptions applied in measuring net benefit pension cost and/or the projected benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and the accumulated benefit obligation. Similar assumptions as described above, except for the assumption of the expected long-term rate of return on pension plan assets, which is applicable only to the OPEB plan at Central Hudson, along with the health care cost trend rate, were also utilized by management in determining net OPEB cost and accumulated benefit obligation.

The OPEB plan assets at Central Hudson experienced total positive returns of approximately $12 million in 2013 compared to expected positive returns of approximately $4 million.

The following table provides the sensitivities associated with a 100 basis point change in the health care cost trend rate and the discount rate on 2013 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2013 Annual Consolidated Financial Statements.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate

Year Ended December 31, 2013

Increase (decrease) *($ millions)*	**Net OPEB cost**	**Accumulated benefit obligation**
Impact of increasing the health care cost trend rate assumption by 100 basis points	3	38
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(2)	(31)
Impact of increasing the discount rate assumption by 100 basis points	(5)	(56)
Impact of decreasing the discount rate assumption by 100 basis points	5	66

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made. Any difference between the cash payments made during the year and the cost incurred during the year is deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions result in changes in regulatory assets and regulatory liabilities for FortisAlberta. The FortisBC Energy companies, Central Hudson, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net pension cost from forecast net pension cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2013, for all defined benefit pension and OPEB plans, the Corporation had consolidated benefit obligations of $2,141 million (December 31, 2012 – $1,417 million) and consolidated plan assets of $1,662 million (December 31, 2012 – $868 million), for a consolidated funded status in a liability position of $479 million (December 31, 2012 – $549 million). During 2013 the Corporation recognized consolidated net benefit cost of $77 million (2012 – $62 million) for all defined benefit pension and OPEB plans.

AROs: The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. There are also uncertainties in estimating future asset-retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights-of-way at the end of the life of the systems and the remediation of certain land, no amounts were recognized as at December 31, 2013 and 2012, with the exception of AROs recognized by FortisBC Electric and Central Hudson.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and T&D assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

As at December 31, 2013, FortisBC Electric recognized an approximate $2 million ARO (December 31, 2012 – $3 million) associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from electrical equipment and Central Hudson recognized an approximate $1 million ARO associated primarily with asbestos remediation. The total ARO liability as at December 31, 2013 has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating the companies' AROs represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the companies' current assumptions. The AROs may change from period to period because of changes in the estimation of these uncertainties. Other subsidiaries also affected by AROs associated with the removal of PCB-contaminated oil from electrical equipment include Central Hudson, FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. As at December 31, 2013, the AROs related to PCBs for the above-noted utilities were not material and, therefore, were not recognized.

Revenue Recognition: Revenue at the Corporation's regulated utilities is generally recognized on an accrual basis. Gas and electricity consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, with the exception of certain electricity customers at Central Hudson, as approved by the regulator. As at December 31, 2013, approximately $14 million (US$13 million) in unbilled revenue at Central Hudson associated with these electricity customers was not accrued.

The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the gas and electricity sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2013, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $341 million (December 31, 2012 – $284 million) on annual consolidated revenue of $4,047 million for 2013 (2012 – $3,654 million). The increase in accrued unbilled revenue of $57 million from December 31, 2012 was due to the acquisition of Central Hudson, higher T&D revenue at FortisAlberta, and higher electricity sales at FortisBC Electric and Newfoundland Power.

Capitalized Overhead: As required by their respective regulator, the FortisBC Energy companies, Central Hudson, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recognized as operating expenses versus utility capital assets. Effective January 1, 2013, FortisOntario is no longer permitted to capitalize overhead costs that are not directly attributable to specific utility capital assets.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Fortis

In May 2012 CH Energy Group and Fortis entered into a proposed settlement agreement with counsel to plaintiff shareholders pertaining to several complaints, which named Fortis and other defendants, which were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, relating to the acquisition of CH Energy Group by Fortis. The complaints generally alleged that the directors of CH Energy Group breached their fiduciary duties in connection with the acquisition and that CH Energy Group, Fortis, FortisUS Inc. and Cascade Acquisition Sub Inc. aided and abetted that breach. The settlement agreement is subject to court approval. In February 2014 the Supreme Court of the State of New York, County of New York, issued a Consent Order preliminarily certifying the matter as a class action and providing directions leading to a Settlement Hearing to be held in June 2014.

Following the announcement of the proposed acquisition of UNS Energy on December 11, 2013, several complaints, which named Fortis and other defendants, were filed in the Superior Court of Arizona, Pima County, and the United States District Court of the District of Arizona, challenging the proposed acquisition. The complaints generally allege that the directors of UNS Energy breached their fiduciary duties in connection with the proposed acquisition and that UNS Energy, Fortis, FortisUS Inc. and Color Acquisition Sub Inc. aided and abetted that breach.

The outcome of these lawsuits cannot be predicted with any certainty and, accordingly, no amount has been accrued in the consolidated financial statements. An adverse judgment for monetary damages could have a material adverse effect on the operations of the surviving company after the completion of the acquisition. A preliminary injunction could delay or jeopardize the completion of the acquisition and an adverse judgment granting permanent injunctive relief could indefinitely enjoin completion of the transaction. Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of such lawsuits is not expected to have a material adverse effect on the consolidated financial condition of Fortis. The defendants intend to vigorously defend themselves against the lawsuits.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FEI was the plaintiff in a British Columbia Supreme Court action against the City of Surrey ("Surrey") in which FEI sought the court's determination on the manner in which costs related to the relocation of a natural gas transmission pipeline would be shared between the Company and Surrey. The relocation was required due to the development and expansion of Surrey's transportation infrastructure. FEI claimed that the parties had an agreement that dealt with the allocation of costs. Surrey advanced counterclaims, including an allegation that FEI breached the agreement and that Surrey suffered damages as a result. In December 2013 the court issued a decision ordering FEI and Surrey to share equally the cost of the pipeline relocation. The court also decided that Surrey was successful in its counterclaim that FEI breached the agreement. The amount of damages that may be awarded to Surrey at a subsequent hearing cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake in 2003, prior to the acquisition of FortisBC Electric by Fortis, and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has disclosed that its claim includes approximately $15 million in damages as well as pre-judgment interest, but that it has not fully quantified its damages. FortisBC Electric and its insurers continue to defend the claim by the Government of British Columbia. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has not been served, the Company has retained counsel and has notified its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Central Hudson

Former MGP Facilities

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid- to late 1800s with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The DEC, which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2013, an obligation of US$41 million was recognized in respect of MGP remediation and, based upon cost model analysis completed in 2012, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$152 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return.

Eltings Corners

Central Hudson owns and operates a maintenance and warehouse facility. In the course of Central Hudson's hazardous waste permit renewal process for this facility, sediment contamination was discovered within the wetland area across the street from the main property. Based on the investigation work completed by Central Hudson, the DEC and Central Hudson agreed in late 2013 that no additional investigation efforts are necessary. As requested by the DEC, Central Hudson submitted a draft Corrective Measures Study scoping document for review by the DEC. Although the extent of the contamination has now been established, the timing and costs for any future remediation efforts cannot be reasonably estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Asbestos Litigation

Prior to the acquisition of CH Energy Group, various asbestos lawsuits had been brought against Central Hudson. While a total of 3,342 asbestos cases have been raised, 1,170 remained pending as at December 31, 2013. Of the cases no longer pending against Central Hudson, 2,017 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 155 cases. The Company is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2013, 2012 and 2011.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2013**	2012	2011
Revenue	**4,047**	3,654	3,738
Net earnings	**420**	371	366
Net earnings attributable to common equity shareholders	**353**	315	311
Basic earnings per common share	**1.74**	1.66	1.71
Diluted earnings per common share	**1.73**	1.65	1.70
Total assets	**17,908**	14,950	14,214
Long-term debt (including current portion)	**7,204**	5,900	5,788
Preference shares	**1,229**	1,108	912
Common shareholders' equity	**4,772**	3,992	3,823
Dividends declared per common share	**1.25**	1.21	1.17
Dividends declared per First Preference Share, Series C [(1)]	**0.4862**	1.3625	1.3625
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series F	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series G [(2)]	**1.1416**	1.3125	1.3125
Dividends declared per First Preference Share, Series H	**1.0625**	1.0625	1.0625
Dividends declared per First Preference Share, Series J [(3)]	**1.1875**	0.3514	–
Dividends declared per First Preference Share, Series K [(4)]	**0.6233**	–	–

[(1)] In July 2013 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series C at a redemption price of $25.1456 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share.

[(2)] The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.

[(3)] The First Preference Shares, Series J were issued in November 2012 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.1875 per share per annum.

[(4)] The Fixed Rate Reset First Preference Shares, Series K were issued in July 2013 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.0000 per share per annum for the first six years.

2013/2012: Revenue increased $393 million, or 10.8%, from 2012 and net earnings attributable to common equity shareholders grew to $353 million, up $38 million from 2012. For a discussion of the reasons for the changes in revenue and net earnings attributable to common equity shareholders, refer to the "Consolidated Results of Operations" and "Summary Financial Highlights" sections of this MD&A.

The growth in total assets reflects the Corporation's acquisition of CH Energy Group in June 2013 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities in western Canada and the continued construction of the Waneta Expansion. The increase in long-term debt was primarily due to the financing of the acquisition of CH Energy Group, including debt assumed on acquisition, and in support of energy infrastructure investment.

Basic earnings per common share were $1.74 in 2013 compared to $1.66 in 2012. The increase was due to higher net earnings attributable to common equity shareholders, partially offset by the impact of a 6.6% increase in the weighted average number of common shares outstanding, largely due to the issuance of 18.5 million common shares pursuant to the conversion of Subscription Receipts on closing of the acquisition of CH Energy Group in June 2013.

2012/2011: Revenue decreased $84 million, or 2.2%, from 2011. The decrease was mainly due to: (i) lower cost of natural gas charged to customers; (ii) the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility effective June 2011; (iii) lower average gas consumption by residential and commercial customers, driven by overall warmer temperatures; and (iv) lower non-regulated hydroelectric production, mainly due to lower rainfall and a generating facility in Upstate New York being out of service in 2012. The decrease was partially offset by: (i) an increase in the base component of rates at most of the regulated utilities; (ii) net transmission revenue of approximately $8.5 million recognized in 2012 at FortisAlberta; (iii) the flow through in customer electricity rates of higher energy supply costs, where applicable, at most of the regulated electric utilities; (iv) increased electricity sales mainly at Newfoundland Power and Maritime Electric; (v) a $4 million increase in franchise fee revenue in 2012 at FortisAlberta; (vi) growth in the number of customers, driven by FortisAlberta; (vii) higher pole-attachment revenue at FortisBC Electric and differences in the amount of PBR incentives refunded to FortisBC Electric's customers year over year; and (viii) higher Hospitality Division revenue at Fortis Properties.

Net earnings attributable to common equity shareholders were $315 million compared to $311 million for 2011. Excluding: (i) the $7.5 million after-tax CH Energy Group acquisition-related expenses; and (ii) the one-time $11 million after-tax fee paid to Fortis in 2011 following the termination of a Merger Agreement with Central Vermont Public Service Corporation, earnings increased approximately $22 million over 2011. The increase in earnings was mainly due to improved performance at the Canadian Regulated Utilities, associated with: (i) rate base growth, driven by the utilities in western Canada; (ii) net transmission revenue of $8.5 million and lower-than-expected depreciation expense and finance charges in 2012, partially offset by a $1 million gain on the sale of property in 2011 at FortisAlberta; (iii) lower effective income taxes at Newfoundland Power and Maritime Electric; (iv) higher pole-attachment revenue and lower-than-expected finance charges in 2012 at FortisBC Electric, partially offset by the discontinuance of the PBR mechanism in December 2011; (v) the cumulative return earned on capital investment in smart meters at FortisOntario in 2012; and (vi) higher gas transportation volumes to industrial customers, lower-than-expected operating expenses in 2012 and lower effective income taxes at the FortisBC Energy companies, partially offset by lower capitalized AFUDC. The above-noted increases were partially offset by: (i) higher Corporate and Other expenses, mainly due to a $2 million foreign exchange loss recognized in 2012, compared to a $1.5 million after-tax foreign exchange gain recognized in 2011; and (ii) decreased earnings from non-regulated hydroelectric generation operations due to lower production and decreased earnings at Fortis Properties, reflecting lower performance in the Hospitality Division and increased depreciation.

The growth in total assets reflected the Corporation's continued investment in regulated energy systems, driven by capital spending at the regulated utilities in western Canada, and the continued construction of the non-regulated Waneta Expansion. The increase in long-term debt was in support of energy infrastructure investment, partially offset by the repayment in 2012 of committed corporate credit facility borrowings, classified as long term, with a portion of the proceeds from the Corporation's $200 million preference share offering.

Basic earnings per common share were $1.66 in 2012 compared to $1.71 in 2011. The decrease was due to the impact of a 5% increase in the weighted average number of common shares outstanding, largely associated with the public common equity offering in mid-2011, partially offset by higher net earnings attributable to common equity shareholders.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2013 and 2012. A discussion of the financial results for the fourth quarter of 2013 is also contained in the Corporation's fourth quarter 2013 media release, dated and filed on SEDAR at www.sedar.com on February 6, 2014, which is incorporated by reference in this MD&A.

Summary of Gas Volumes and Energy and Electricity Sales

Fourth Quarters Ended December 31 *(Unaudited)*	2013	2012	Variance
Regulated Gas Utilities – Canadian *(PJ)*			
FortisBC Energy Companies	**68**	60	8
Regulated Gas & Electric Utility – United States			
Central Hudson – Gas Volumes *(PJ)*	**5**	–	5
Central Hudson – Electricity Sales *(GWh)*	**1,209**	–	1,209
Regulated Electric Utilities – Canadian *(GWh)*			
FortisAlberta	**4,523**	4,365	158
FortisBC Electric	**887**	830	57
Newfoundland Power	**1,583**	1,539	44
Other Canadian Electric Utilities	**596**	578	18
	7,589	7,312	277
Regulated Electric Utilities – Caribbean *(GWh)*	**189**	181	8
Non-Regulated – Fortis Generation *(GWh)*	**144**	50	94

Gas Volumes

The increase in gas volumes was driven by higher average consumption by residential, commercial and transportation customers at the FortisBC Energy companies due to colder weather. Gas volumes also increased as a result of the acquisition of Central Hudson.

Energy and Electricity Sales

The increase in energy deliveries at FortisAlberta was driven by growth in the number of customers, mainly residential and commercial customers. The increase was partially offset by lower average consumption by residential, commercial, and farm and irrigation customers due to reduced heating load.

The increase in electricity sales was primarily due to the acquisition of Central Hudson, increased non-regulated hydroelectric production in Belize due to higher rainfall and higher average consumption by customers at FortisBC Electric, Newfoundland Power and Maritime Electric due to cooler temperatures in the fourth quarter of 2013. Customer growth at Newfoundland Power and the Caribbean utilities, and warmer temperatures on Grand Cayman, resulting in increased air conditioning load, also favourably impacted electricity sales quarter over quarter. The above-noted increases were partially offset by lower average consumption by customers in Ontario, reflecting more moderate temperatures, energy conservation and continuing weak economic conditions in the region.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*	Revenue			Net Earnings		
($ millions, except per share amounts)	2013	2012	Variance	2013	2012	Variance
Regulated Gas Utilities – Canadian						
FortisBC Energy Companies	**446**	422	24	**50**	49	1
Regulated Gas & Electric Utility – United States						
Central Hudson	**165**	–	165	**11**	–	11
Regulated Electric Utilities – Canadian						
FortisAlberta	**121**	113	8	**18**	23	(5)
FortisBC Electric	**87**	81	6	**13**	12	1
Newfoundland Power	**167**	159	8	**10**	9	1
Other Canadian Electric Utilities	**94**	89	5	**4**	5	(1)
	469	442	27	**45**	49	(4)
Regulated Electric Utilities – Caribbean	**77**	71	6	**8**	4	4
Non-Regulated – Fortis Generation	**11**	5	6	**4**	2	2
Non-Regulated – Non-Utility	**62**	61	1	**3**	5	(2)
Corporate and Other	**7**	6	1	**(21)**	(22)	1
Inter-Segment Eliminations	**(8)**	(8)	–	**–**	–	–
Total	**1,229**	999	230	**100**	87	13
Basic Earnings per Common Share *($)*				**0.47**	0.46	0.01

Revenue

The increase in revenue was driven by the acquisition of Central Hudson, an increase in the base component of rates at most of the regulated utilities, higher electricity sales and gas volumes, and favourable foreign exchange associated with the translation of US dollar-denominated revenue.

The increase was partially offset by decreases in the allowed ROEs at the FortisBC Energy companies and FortisBC Electric, and a decrease in the equity component of capital structure at FEI, effective January 1, 2013, as a result of the regulatory decision on the first stage of the GCOC Proceeding in British Columbia, and lower net transmission revenue at FortisAlberta.

Earnings

The increase in earnings was primarily due to: (i) the acquisition of CH Energy Group, including contribution of $11 million from Central Hudson and a net loss of approximately $2 million at the non-regulated operations; (ii) increased non-regulated hydroelectric production in Belize, partially offset by income tax expenses associated with the Exploits Partnership; (iii) higher earnings at Caribbean Regulated Electric Utilities, driven by the capitalization of overhead costs at Fortis Turks and Caicos; (iv) higher earnings at the FortisBC Energy companies and FortisBC Electric, mainly due to lower-than-expected finance charges and rate base growth, partially offset by decreases in the allowed ROEs for each of the utilities and the equity component of capital structure at FEI; and (v) a gain on the sale of land at Newfoundland Power. The increase was partially offset by lower earnings at FortisAlberta and Other Canadian Electric Utilities. The timing of depreciation and certain operating expenses and lower net transmission revenue at FortisAlberta were partially offset by rate base growth and growth in the number of customers. At Other Canadian Electric Utilities, the decrease was primarily due to the impact of the cumulative return adjustment on smart meter investments at FortisOntario in 2012. Corporate and Other expenses were comparable quarter over quarter.

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2013**	2012	Variance
Cash, Beginning of Period	**155**	147	8
Cash Provided by (Used in):			
Operating Activities	**233**	176	57
Investing Activities	**(344)**	(323)	(21)
Financing Activities	**31**	154	(123)
Less Cash at Discontinued Operations	**(3)**	–	(3)
Cash, End of Period	**72**	154	(82)

Cash flow from operating activities was $57 million higher quarter over quarter. The increase was primarily due to favourable changes in working capital, mainly at Maritime Electric and FortisAlberta, combined with higher earnings and the collection from customers of regulator-approved increases in depreciation and amortization.

Cash used in investing activities was $21 million higher quarter over quarter. The increase was mainly due to higher capital expenditures at the regulated utilities, including capital spending at Central Hudson, partially offset by lower capital expenditures at FortisAlberta and the non-regulated Waneta Expansion.

Cash provided by financing activities was $123 million lower quarter over quarter due to: (i) proceeds from the issuance of preference shares in November 2012; (ii) higher repayments under committed credit facilities; and (iii) higher repayments of long-term debt. The decrease was partially offset by higher proceeds from long-term debt.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2012 through December 31, 2013. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results
(Unaudited)

Quarter Ended	Revenue *($ millions)*	Net Earnings Attributable to Common Equity Shareholders *($ millions)*	Earnings per Common Share Basic *($)*	Earnings per Common Share Diluted *($)*
December 31, 2013	1,229	100	0.47	0.47
September 30, 2013	915	48	0.23	0.23
June 30, 2013	790	54	0.28	0.28
March 31, 2013	1,113	151	0.79	0.76
December 31, 2012	999	87	0.46	0.45
September 30, 2012	714	45	0.24	0.24
June 30, 2012	792	62	0.33	0.33
March 31, 2012	1,149	121	0.64	0.62

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters.

December 2013/December 2012: Net earnings attributable to common equity shareholders were $100 million, or $0.47 per common share, for the fourth quarter of 2013 compared to earnings of $87 million, or $0.46 per common share, for the fourth quarter of 2012. A discussion of the variances between the financial results for the fourth quarter of 2013 and the fourth quarter of 2012 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2013/September 2012: Net earnings attributable to common equity shareholders were $48 million, or $0.23 per common share, for the third quarter of 2013 compared to earnings of $45 million, or $0.24 per common share, for the third quarter of 2012. Results for the third quarter of 2013 were impacted by the acquisition of CH Energy Group. Central Hudson contributed $12 million to earnings for the third quarter of 2013 and Griffith incurred a net loss of approximately $2.5 million. Due to the common share offering and financing costs associated with the acquisition, earnings per common share for the third quarter of 2013 were not materially impacted by the acquisition of CH Energy Group. Earnings for the third quarter of 2013 were favourably impacted by increased non-regulated hydroelectric generation in Belize, due to higher rainfall, and lower Corporate expenses. Lower Corporate expenses were primarily due to a higher income tax recovery, resulting from the release of income tax provisions in the third quarter of 2013 and the recognition of income tax expense associated with Part VI.1 tax in the third quarter of 2012, and a lower foreign exchange loss, partially offset by higher preference share dividends and redemption costs. The increase in earnings was partially offset by lower contribution from the FortisBC Energy companies, FortisBC Electric, FortisAlberta and Newfoundland Power. At the FortisBC Energy companies, lower earnings were primarily due to higher operating and maintenance expenses, and decreases in the allowed ROE and the equity component of the capital structure as a result of the regulatory decision related to the first stage of the GCOC Proceeding in British Columbia, partially offset by rate base growth. Decreased earnings at FortisBC Electric were mainly due to a decrease in the interim allowed ROE as a result of the regulatory decision related to the first stage of the GCOC Proceeding in British Columbia, lower pole-attachment revenue and higher effective income taxes, partially offset by rate base growth and lower-than-expected finance charges. At FortisAlberta, lower net transmission revenue and $1 million of costs related to flooding in southern Alberta in June 2013 were largely offset by rate base growth, customer growth and timing of operating expenses. Decreased earnings at Newfoundland Power due to the reversal of statute-barred Part VI.1 tax in the third quarter of 2012 were partially offset by rate base growth and lower storm-related costs.

June 2013/June 2012: Net earnings attributable to common equity shareholders were $54 million, or $0.28 per common share, for the second quarter of 2013 compared to earnings of $62 million, or $0.33 per common share, for the second quarter of 2012. Earnings for the second quarter of 2013 were reduced by $32 million due to acquisition-related expenses and customer and community benefits offered to obtain regulatory approval of the acquisition of CH Energy Group, compared to $3 million of acquisition-related expenses in the second quarter of 2012. Earnings for the second quarter of 2013 were favourably impacted by an income tax recovery of $25 million due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends. In the second quarter of 2012, earnings were reduced by income tax expenses of $3 million associated with Part VI.1 tax. Excluding the above-noted acquisition-related and Part VI.1 tax impacts, net earnings for the second quarter of 2013 were $61 million compared to $68 million for the second quarter of 2012. The decrease in earnings was mainly due to lower contribution from the FortisBC Energy companies, FortisAlberta and FortisBC Electric, and decreased non-regulated hydroelectric production in Belize due to lower rainfall, partially offset by lower Corporate expenses. Earnings at the FortisBC Energy companies and FortisBC Electric were reduced by $8 million and $2 million, respectively, as a result of the regulatory decision related to the first stage of the GCOC Proceeding in British Columbia, which was received in the second quarter of 2013. At the FortisBC Energy companies, earnings contribution from rate base growth was largely offset by lower gas transportation volumes. FortisAlberta's earnings decreased due to lower net transmission revenue and timing of the recognition of a regulatory decision in 2012 impacting depreciation, partially offset by the timing of operating expenses, rate base growth and customer growth. At FortisBC Electric, lower-than-expected finance charges, rate base growth and higher capitalized AFUDC favourably impacted earnings. Lower Corporate expenses were primarily due to the favourable impact of the release of income tax provisions in the second quarter of 2013, a higher foreign exchange gain and lower finance charges, partially offset by higher preference share dividends.

March 2013/March 2012: Net earnings attributable to common equity shareholders were $151 million, or $0.79 per common share, for the first quarter of 2013 compared to earnings of $121 million, or $0.64 per common share, for the first quarter of 2012. Earnings for the first quarter of 2013 included an extraordinary gain of approximately $22 million after tax upon the settlement of expropriation matters associated with the Exploits Partnership. The remainder of the increase in earnings was primarily due to higher contribution from FortisAlberta, the FortisBC Energy companies and FortisBC Electric, and lower Corporate expenses. Higher earnings at FortisAlberta were primarily due to lower depreciation and net transmission revenue of approximately $2 million recognized in the first quarter of 2013 associated with the finalization of 2012 net transmission volume variances. At the FortisBC Energy companies, improved performance was mainly due to rate base growth and increased gas transportation volumes, partially offset by higher effective income taxes. Increased earnings at FortisBC Electric due to rate base growth, timing of operating expenses, lower-than-expected finance charges and depreciation, and higher capitalized AFUDC were partially offset by higher effective income taxes. Corporate expenses for the first quarter of 2013 were reduced by $2 million related to foreign exchange, while Corporate expenses for the first quarter of 2012 were increased by $1.5 million related to foreign exchange. Acquisition-related expenses in the first quarter of 2013 were approximately $0.5 million after tax compared to $4 million after tax in the first quarter of 2012. Excluding foreign exchange impacts and acquisition-related expenses noted above, Corporate expenses increased quarter over quarter mainly due to higher preference share dividends, partially offset by lower finance charges. The increase in earnings was partially offset by decreased non-regulated hydroelectric production in Belize due to lower rainfall and lower earnings at Maritime Electric and Fortis Properties.

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures: The President and CEO and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2013 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting: The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with US GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2013 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2013, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

SUBSEQUENT EVENTS

Convertible Debentures Represented by Installment Receipts

To finance a portion of the pending acquisition of UNS Energy, in January 2014 Fortis, through a direct wholly owned subsidiary, completed the sale of $1.8 billion aggregate principal amount of 4% Debentures of the Corporation. For further information, refer to the "Significant Items – Convertible Debentures Represented by Installment Receipts" section of this MD&A.

Sale of Griffith

In March 2014 CH Energy Group sold its non-regulated subsidiary, Griffith, for approximately US$70 million plus working capital.

OUTLOOK

Fortis is focused on closing the UNS Energy acquisition by the end of 2014. The acquisition is consistent with the Corporation's strategy of investing in high-quality regulated utility assets in Canada and the United States and is expected to be accretive to earnings per common share of Fortis in the first full year after closing, excluding one-time acquisition-related costs. The acquisition lessens the business risk for Fortis by enhancing the geographic diversification of the Corporation's regulated assets, resulting in no more than one-third of total assets being located in any one regulatory jurisdiction.

At the time of closing the acquisition of UNS Energy, the Corporation's consolidated rate base is expected to increase by approximately US$3 billion, and Fortis utilities will serve more than 3,000,000 electricity and gas customers.

Over the five-year period 2014 through 2018, the Corporation's capital program is expected to exceed $6.5 billion, and will support continuing growth in earnings and dividends. Additionally, UNS Energy has forecast that its capital program for 2015 through 2018 will be approximately $1.5 billion (US$1.4 billion).

Following closing of the acquisition of UNS Energy, regulated utilities in the United States will represent approximately one-third of total assets, and regulated utilities and hydroelectric generation assets will comprise approximately 97% of the Corporation's total assets.

The Corporation expects earnings per common share growth in 2015 and beyond as a result of contributions from the Central Hudson and UNS Energy acquisitions, and the completion of the Waneta Expansion in 2015 and the Tilbury LNG facility expansion in 2016, which will support continuing growth in dividends.

OUTSTANDING SHARE DATA

As at March 12, 2014, the Corporation had issued and outstanding 214.1 million common shares; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 10.0 million First Preference Shares, Series H; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 1.8 million Installment Receipts. Only the common shares of the Corporation have voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options, First Preference Shares, Series E and convertible debentures represented by Installment Receipts were converted as at March 12, 2014 is as follows.

Conversion of Securities into Common Shares

As at March 12, 2014 *(Unaudited)*

Security	Number of Common Shares *(millions)*
Stock Options	**6.0**
First Preference Shares, Series E	**6.8**
Convertible Debentures Represented by Installment Receipts	**58.6**
Total	**71.4**

Additional information, including the Fortis 2013 Annual Information Form, Management Information Circular and Audited Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

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Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2013 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States. Financial information contained elsewhere in the 2013 Annual Report is consistent with that in the Annual Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2013 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2013 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2013 Annual Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer, Fortis Inc.

Barry V. Perry
Vice President, Finance and Chief Financial Officer, Fortis Inc.

St. John's, Canada

Independent Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheets as at December 31, 2013 and 2012 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for the years then ended, and 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 accounting principles generally accepted in the United States, 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. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance whether the consolidated financial statements are free of 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 the auditors' 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, the auditors 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, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. 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, these consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2013 and 2012 and its financial performance and cash flows for the years then ended in accordance with accounting principles generally accepted in the United States.

Ernst & Young LLP
Chartered Accountants

St. John's, Canada
March 13, 2014

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in millions of Canadian dollars)

ASSETS	**2013**	2012
Current assets		
Cash and cash equivalents	**$ 72**	$ 154
Accounts receivable *(Note 5)*	**732**	587
Prepaid expenses	**45**	18
Inventories *(Note 6)*	**143**	133
Regulatory assets *(Note 7)*	**150**	185
Assets held for sale *(Note 8)*	**112**	–
Deferred income taxes *(Note 26)*	**42**	16
	1,296	1,093
Other assets *(Note 9)*	**246**	200
Regulatory assets *(Note 7)*	**1,672**	1,515
Deferred income taxes *(Note 26)*	**7**	–
Utility capital assets *(Note 10)*	**11,618**	9,623
Non-utility capital assets *(Note 11)*	**649**	626
Intangible assets *(Note 12)*	**345**	325
Goodwill *(Note 13)*	**2,075**	1,568
	$ 17,908	$ 14,950
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 34)*	**$ 160**	$ 136
Accounts payable and other current liabilities *(Note 14)*	**957**	966
Regulatory liabilities *(Note 7)*	**140**	72
Current installments of long-term debt *(Note 15)*	**780**	159
Current installments of capital lease and finance obligations *(Note 16)*	**7**	7
Liabilities associated with assets held for sale *(Note 8)*	**32**	–
Deferred income taxes *(Note 26)*	**8**	10
	2,084	1,350
Other liabilities *(Note 17)*	**627**	638
Regulatory liabilities *(Note 7)*	**902**	681
Deferred income taxes *(Note 26)*	**1,078**	702
Long-term debt *(Note 15)*	**6,424**	5,741
Capital lease and finance obligations *(Note 16)*	**417**	428
	11,532	9,540
Shareholders' equity		
Common shares [(1)] *(Note 18)*	**3,783**	3,121
Preference shares *(Note 20)*	**1,229**	1,108
Additional paid-in capital	**17**	15
Accumulated other comprehensive loss *(Note 21)*	**(72)**	(96)
Retained earnings	**1,044**	952
	6,001	5,100
Non-controlling interests *(Note 22)*	**375**	310
	6,376	5,410
	$ 17,908	$ 14,950

[(1)] No par value. Unlimited authorized shares; 213.2 million and 191.6 million issued and outstanding as at December 31, 2013 and 2012, respectively

Commitments *(Note 35)*
Expropriated assets *(Note 36)*
Contingencies *(Note 37)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

David G. Norris,
Director

Peter E. Case,
Director

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2013**	2012
Revenue	**$ 4,047**	$ 3,654
Expenses		
Energy supply costs	**1,617**	1,522
Operating	**1,037**	868
Depreciation and amortization	**541**	470
	3,195	2,860
Operating income	**852**	794
Other income (expenses), net *(Note 24)*	**(31)**	4
Finance charges *(Note 25)*	**389**	366
Earnings before income taxes, discontinued operations and extraordinary item	**432**	432
Income tax expense *(Note 26)*	**32**	61
Earnings from continuing operations	**400**	371
Earnings from discontinued operations, net of tax *(Note 8)*	**–**	–
Earnings before extraordinary item	**400**	371
Extraordinary gain, net of tax *(Note 27)*	**20**	–
Net earnings	**$ 420**	$ 371
Net earnings attributable to:		
Non-controlling interests	**$ 10**	$ 9
Preference equity shareholders	**57**	47
Common equity shareholders	**353**	315
	$ 420	$ 371
Earnings per common share from continuing operations *(Note 19)*		
Basic	**$ 1.64**	$ 1.66
Diluted	**$ 1.63**	$ 1.65
Earnings per common share *(Note 19)*		
Basic	**$ 1.74**	$ 1.66
Diluted	**$ 1.73**	$ 1.65

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2013**	2012
Net earnings	**$ 420**	$ 371
Other comprehensive income (loss)		
Unrealized foreign currency translation gains (losses), net of hedging activities and tax *(Note 21)*	**16**	(2)
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax *(Note 21)*	**1**	1
Unrealized employee future benefits gains, net of tax *(Notes 21 and 28)*	**7**	–
	24	(1)
Comprehensive income	**$ 444**	$ 370
Comprehensive income attributable to:		
Non-controlling interests	**$ 10**	$ 9
Preference equity shareholders	**57**	47
Common equity shareholders	**377**	314
	$ 444	$ 370

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2013**	2012
Operating activities		
Net earnings	**$ 420**	$ 371
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – capital assets	**475**	424
Amortization – intangible assets	**49**	44
Amortization – other	**17**	2
Deferred income tax (recovery) expense *(Note 26)*	**(6)**	17
Accrued employee future benefits	**17**	10
Equity component of allowance for funds used during construction *(Note 24)*	**(8)**	(7)
Other	**(34)**	(1)
Change in long-term regulatory assets and liabilities	**14**	54
Change in non-cash operating working capital *(Note 31)*	**(45)**	78
	899	992
Investing activities		
Change in other assets and other liabilities	**(8)**	–
Capital expenditures – utility capital assets	**(1,089)**	(1,069)
Capital expenditures – non-utility capital assets	**(46)**	(35)
Capital expenditures – intangible assets	**(40)**	(42)
Contributions in aid of construction	**54**	68
Proceeds on disposal and settlement of assets	**20**	3
Business acquisitions, net of cash acquired *(Note 29)*	**(1,055)**	(21)
	(2,164)	(1,096)
Financing activities		
Change in short-term borrowings	**(6)**	(22)
Proceeds from long-term debt, net of issue costs	**653**	124
Repayments of long-term debt and capital lease and finance obligations	**(173)**	(88)
Net borrowings under committed credit facilities	**184**	71
Advances from non-controlling interests	**63**	106
Subscription Receipts issue costs *(Notes 9 and 18)*	**–**	(13)
Issue of common shares, net of costs and dividends reinvested	**596**	24
Issue of preference shares, net of costs *(Note 20)*	**242**	194
Redemption of preference shares *(Note 20)*	**(125)**	–
Dividends		
Common shares, net of dividends reinvested	**(181)**	(170)
Preference shares	**(56)**	(46)
Subsidiary dividends paid to non-controlling interests	**(11)**	(9)
	1,186	171
Change in cash and cash equivalents	**(79)**	67
Less cash at discontinued operations *(Note 8)*	**(3)**	–
Cash and cash equivalents, beginning of year	**154**	87
Cash and cash equivalents, end of year	**$ 72**	$ 154

Supplementary Information to Consolidated Statements of Cash Flows *(Note 31)*

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Changes in Equity

FORTIS INC.

For the years ended December 31, 2013 and 2012 (in millions of Canadian dollars)	**Common Shares**	**Preferences Shares**	**Additional Paid-in Capital**	**Accumulated Other Comprehensive Loss**	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
	(Note 18)	*(Note 20)*		*(Note 21)*		*(Note 22)*	
As at January 1, 2013	**$ 3,121**	**$ 1,108**	**$ 15**	**$ (96)**	**$ 952**	**$ 310**	**$ 5,410**
Net earnings	**–**	**–**	**–**	**–**	**410**	**10**	**420**
Other comprehensive income	**–**	**–**	**–**	**24**	**–**	**–**	**24**
Preference share issue	**–**	**244**	**–**	**–**	**–**	**–**	**244**
Preference share redemption	**–**	**(123)**	**–**	**–**	**–**	**–**	**(123)**
Common share issues	**662**	**–**	**(1)**	**–**	**–**	**–**	**661**
Stock-based compensation	**–**	**–**	**3**	**–**	**–**	**–**	**3**
Advances from non-controlling interests	**–**	**–**	**–**	**–**	**–**	**63**	**63**
Foreign currency translation impacts	**–**	**–**	**–**	**–**	**–**	**3**	**3**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**(11)**	**(11)**
Dividends declared on common shares ($1.25 per share)	**–**	**–**	**–**	**–**	**(261)**	**–**	**(261)**
Dividends declared on preference shares	**–**	**–**	**–**	**–**	**(57)**	**–**	**(57)**
As at December 31, 2013	**$ 3,783**	**$ 1,229**	**$ 17**	**$ (72)**	**$ 1,044**	**$ 375**	**$ 6,376**
As at January 1, 2012	$ 3,036	$ 912	$ 14	$ (95)	$ 868	$ 208	$ 4,943
Net earnings	–	–	–	–	362	9	371
Other comprehensive loss	–	–	–	(1)	–	–	(1)
Preference share issue	–	196	–	–	–	–	196
Common share issues	85	–	(3)	–	–	–	82
Stock-based compensation	–	–	4	–	–	–	4
Advances from non-controlling interests	–	–	–	–	–	106	106
Foreign currency translation impacts	–	–	–	–	–	(4)	(4)
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	(9)	(9)
Dividends declared on common shares ($1.21 per share)	–	–	–	–	(231)	–	(231)
Dividends declared on preference shares	–	–	–	–	(47)	–	(47)
As at December 31, 2012	$ 3,121	$ 1,108	$ 15	$ (96)	$ 952	$ 310	$ 5,410

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

For the years ended December 31, 2013 and 2012

1. Description of the Business

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international gas and electric distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation and non-utility assets, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The Corporation's interests in regulated gas and electric utilities are as follows:

Regulated Gas Utilities – Canadian

FortisBC Energy Companies: Primarily includes FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI").

FEI is the largest distributor of natural gas in British Columbia, serving more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler, British Columbia.

In addition to providing transmission and distribution ("T&D") services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing Pipeline, from Alberta.

Regulated Gas & Electric Utility – United States

Central Hudson: Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated T&D utility serving eight counties of New York State's Mid-Hudson River Valley. Central Hudson was acquired by Fortis as part of the acquisition of CH Energy Group, Inc. ("CH Energy Group") in June 2013 (Note 29).

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 megawatts ("MW"). Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant ("Brilliant Plant") and the 120-MW Brilliant hydroelectric expansion plant, both owned by Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"), and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT. In March 2013 FortisBC Inc. acquired the City of Kelowna's electrical utility assets (Note 29).

c. *Newfoundland Power:* Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. The Company has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Comprised of Maritime Electric and FortisOntario. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"). Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies (Note 29).

Regulated Electric Utilities – Caribbean

a. *Caribbean Utilities:* Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed diesel-powered generating capacity of 150 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2012 – 60%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U).

b. *Fortis Turks and Caicos:* Comprised of FortisTCI Limited ("FortisTCI") and Turks and Caicos Utilities Limited ("TCU"), which was acquired in August 2012 (collectively "Fortis Turks and Caicos") (Note 29). Both of the Fortis Turks and Caicos utilities are integrated electric utilities and, combined, have a diesel-powered generating capacity of 76 MW. Fortis Turks and Caicos provides electricity to Providenciales, North Caicos, Middle Caicos and South Caicos through FortisTCI, and to Grand Turk and Salt Cay through TCU.

Non-Regulated – Fortis Generation

The following summary describes the Corporation's non-regulated generation assets by location:

a. *Belize:* Comprised of the 25-MW Mollejon, 7-MW Chalillo and 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

b. *Ontario:* Comprised of six small hydroelectric generating facilities in eastern Ontario, with a combined capacity of 8 MW, and a 5-MW gas-powered cogeneration plant in Cornwall.

c. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia, which sells its entire output to BC Hydro. The contract with BC Hydro expired in 2013 and is subject to termination by BC Hydro with five months' notice. Non-regulated generation operations in British Columbia also include the Corporation's 51% controlling ownership interest in the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The Waneta Partnership commenced construction of the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, in late 2010. The Waneta Expansion is expected to come into service in spring 2015. The output of the Waneta Expansion will be sold to BC Hydro and FortisBC Electric under 40-year contracts.

d. *Upstate New York:* Comprised of four hydroelectric generating facilities, with a combined capacity of approximately 23 MW, in Upstate New York, operating under licences from the U.S. Federal Energy Regulatory Commission ("FERC"). Hydroelectric generation operations in Upstate New York are conducted through the Corporation's indirectly wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Non-Utility

a. *Fortis Properties:* Fortis Properties owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces, and owns and operates approximately 2.7 million square feet of commercial office and retail space, primarily in Atlantic Canada (Note 29).

b. *Griffith:* Comprised primarily of Griffith Energy Services, Inc. ("Griffith"), which supplies petroleum products and related services in the Mid-Atlantic Region of the United States. Griffith was acquired by Fortis as part of the acquisition of CH Energy Group (Note 29) and was sold in March 2014 (Note 38). As at December 31, 2013, Griffith has been classified as held for sale (Note 8).

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment, and those business operations that are below the required threshold for reporting as separate segments.

The Corporate and Other segment includes finance charges, comprised of interest on debt incurred directly by Fortis and FortisBC Holdings Inc. ("FHI"); dividends on preference shares; other corporate expenses, including Fortis and FHI corporate operating costs, net of recoveries from subsidiaries; acquisition-related expenses; interest and miscellaneous revenue; and related income taxes.

Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

1. Description of the Business (cont'd)

Pending Acquisition

In December 2013 Fortis entered into an agreement and plan of merger to acquire UNS Energy Corporation ("UNS Energy") (NYSE:UNS) for US$60.25 per common share in cash, representing an aggregate purchase price of approximately US$4.3 billion, including the assumption of approximately US$1.8 billion of debt on closing. The closing of the acquisition, which is expected to occur by the end of 2014, is subject to receipt of UNS Energy common shareholder approval and certain regulatory and government approvals, including approval by the Arizona Corporation Commission and FERC, and compliance with other applicable U.S. legislative requirements and the satisfaction of customary closing conditions (Notes 34, 35, 37 and 38).

UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through three subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 656,000 electricity and gas customers.

2. Nature of Regulation

The nature of regulation at the Corporation's utilities is as follows:

FortisBC Energy Companies and FortisBC Electric

The FortisBC Energy companies and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. FEI, FEVI, FEWI and FortisBC Electric operate under cost of service ("COS") regulation and, from time to time, performance-based rate-setting ("PBR") mechanisms for establishing customer rates.

The BCUC provides for the use of a future test year in the establishment of rates and, pursuant to this method, provides for the forecasting of energy to be sold, together with all the costs of the utilities, and provides a rate of return on a deemed capital structure applied to approved rate base assets. Rates are fixed to permit the utilities to collect all of their costs, including the allowed rate of return on common shareholders' equity ("ROE").

The utilities apply for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible to be deferred on the consolidated balance sheet for future collection from, or refund to, customers ("deferral account treatment") and/or through the operation of PBR mechanisms.

The allowed ROEs for 2012 were set by the BCUC for FEI, FEVI, FEWI and FortisBC Electric. The former automatic adjustment formula used to establish ROEs on an annual basis no longer applies until reviewed further by the BCUC. FEI's allowed ROE was 9.50% for 2012 on a deemed capital structure of 40% common equity. FEVI's and FEWI's allowed ROEs were 10.00% for 2012 on deemed capital structures of 40% common equity. FortisBC Electric's allowed ROE was 9.90% for 2012 on a deemed capital structure of 40% common equity.

In 2013, the BCUC issued its decision on the first stage of the Generic Cost of Capital ("GCOC") Proceeding. Effective January 1, 2013, the decision set the ROE of the benchmark utility at 8.75% on a 38.5% equity component of capital structure. FEI has been designated as the benchmark utility. The equity component of capital structure will remain in effect until December 31, 2015. Effective January 1, 2014 through December 31, 2015, the BCUC is also introducing an Automatic Adjustment Mechanism ("AAM") to set the ROE for the benchmark utility on an annual basis. The AAM will take effect when the long-term Government of Canada bond yield exceeds 3.8%.

FEVI, FEWI and FortisBC Electric will have their allowed ROEs and capital structures determined in the second stage of the GCOC Proceeding. As a result of the BCUC's decision on the first stage of the GCOC Proceeding, which reduced the allowed ROE of the benchmark utility by 75 basis points, the interim allowed ROEs for FEVI, FEWI and FortisBC Electric decreased to 9.25%, 9.25% and 9.15%, respectively, effective January 1, 2013. The deemed equity component of capital structures remained unchanged from 2012 at 40%. The allowed ROEs and equity component of capital structures for FEVI, FEWI and FortisBC Electric could change further as a result of the outcome of the second stage of the GCOC Proceeding.

Central Hudson

Central Hudson is regulated by the New York State Public Service Commission ("PSC") regarding such matters as rates, construction, operations, financing, accounting and issuance of securities. Certain activities of the Company are subject to regulation by FERC under the *Federal Power Act* (United States). Central Hudson is also subject to regulation by the North American Electric Reliability Corporation.

Central Hudson operates under COS regulation as administered by the PSC. The PSC provides for the use of a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the approved rate of return on forecast rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Company's customer rates are determined. Once rates are approved, they are not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Central Hudson's allowed ROE is set at 10% on a deemed capital structure of 48% common equity. The Company began operating under a three-year rate order issued by the PSC effective July 1, 2010. As approved by the PSC in June 2013, the original three-year rate order has been extended for two years, through June 30, 2015, as a condition required to close the acquisition (Note 29). Effective July 1, 2013, Central Hudson is also subject to an earnings sharing mechanism, whereby the Company and customers share equally earnings in excess of the allowed ROE up to an achieved ROE that is 50 basis points above the allowed ROE, and share 10%/90% (Company/customers) earnings in excess of 50 basis points above the allowed ROE.

Central Hudson's approved regulatory regime also allows for full recovery of purchased electricity and natural gas costs. The Company's rates include Revenue Decoupling Mechanisms ("RDMs"), which are intended to minimize the earnings impact resulting from reduced energy consumption as energy-efficiency programs are implemented. The RDMs allow the Company to recognize electric and gas revenue at the levels approved in rates for most of Central Hudson's customer base. Deferral account treatment is approved for certain other specified costs, including provisions for manufactured gas plant ("MGP") site remediation, pension and other post-employment benefit ("OPEB") costs.

FortisAlberta
FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing.

Effective January 1, 2013, the AUC prescribed that distribution utilities in Alberta, including FortisAlberta, move to PBR for a five-year term. Under PBR, a formula that estimates inflation annually and assumes productivity improvements is used to determine distribution rates on an annual basis. Each year this formula is applied to the preceding year's distribution rates and for 2013 the formula was applied to the 2012 distribution rates. In 2012 FortisAlberta operated under COS regulation as prescribed by the AUC, whereby the AUC established the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. The Company applied for tariff revenue based on estimated COS. Once the tariff was approved, it was not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that were eligible for deferral account treatment. FortisAlberta's allowed ROE was 8.75% for 2012 on a deemed capital structure of 41% common equity. For 2013, an allowed ROE of 8.75% was established by the AUC on an interim basis on a deemed capital structure of 41% common equity.

The PBR plan includes mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") and the recovery of costs related to capital expenditures that are not being recovered through the inflationary factor of the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and an ROE efficiency carry-over mechanism. The Z factor permits an application for recovery of costs related to significant unforeseen events. The PBR re-opener permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan. The use of the Z factor and PBR re-opener mechanisms is associated with certain thresholds. The ROE efficiency carry-over mechanism provides an efficiency incentive by permitting a utility to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

The AUC initiated a 2013 GCOC Proceeding to establish the final allowed ROE and capital structure for 2013 and 2014, as well as an interim allowed ROE for 2015, and determine whether a formulaic ROE AAM should be re-established. In this proceeding, the AUC may consider the possibility of re-establishing a formula-based approach to annually set the allowed ROE. A hearing on the 2013 GCOC Proceeding is scheduled for the second quarter of 2014.

Newfoundland Power
Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power.

Newfoundland Power operates under COS regulation as administered by the PUB. The PUB provides for the use of a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the forecast rate of return on approved rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which Newfoundland Power's customer rates are determined.

Generally the utility's allowed ROE is adjusted, between test years, annually through the operation of an AAM for forecast changes in long-term Government of Canada bond rates. The PUB suspended the operation of the ROE AAM for 2012 and ordered a full cost of capital review for 2012. In 2013 the PUB ordered that the allowed ROE and common equity component of capital structure remain at 8.8% and 45%, respectively, for 2013 through 2015, consistent with 2012.

Newfoundland Power applies for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Notes to Consolidated Financial Statements

For the years ended December 31, 2013 and 2012

2. Nature of Regulation (cont'd)

Maritime Electric

Maritime Electric operates under COS regulation as prescribed by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI), the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), which covers the period March 1, 2011 to February 28, 2013, and the *Electric Power (Energy Accord Continuation) Amendment Act* (PEI) ("*Accord Continuation Act*"), which covers the period March 1, 2013 to February 29, 2016.

IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a targeted capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 9.75% for 2013 (2012 – 9.75%) on a targeted minimum capital structure of 40% common equity.

The *Accord Continuation Act* sets out the inputs, rates and other terms for the continuation of the *PEI Energy Accord* for an additional three years covering the period March 1, 2013 through February 29, 2016. Over the three-year period, increases in electricity costs for a typical residential customer have been set at 2.2% annually and Maritime Electric's allowed ROE has been capped at 9.75% each year.

Maritime Electric applies for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario

Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under COS regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation Incentive Regulation Mechanism as prescribed by the OEB.

Canadian Niagara Power's allowed ROE, as determined under the ROE AAM, was calculated at 8.93% for 2013 (2012 – 8.01%) on a deemed capital structure of 40% common equity. The utility's electricity distribution rates for 2012 were based upon forecast 2009 costs, and 2013 electricity distribution rates were based upon a 2013 forward test year.

Algoma Power's allowed ROE was 9.85% for 2013 (2012 – 9.85%) on a deemed capital structure of 40% common equity, and the utility's electricity distribution rates for 2013 and 2012 were based upon forecast 2011 costs. Algoma Power is also subject to the use and implementation of the Rural and Remote Rate Protection ("RRRP") Program. The RRRP Program is calculated as the deficiency between the approved revenue requirement from the OEB and current customer electricity distribution rates, adjusted for the average rate increase across the province of Ontario.

Cornwall Electric is subject to a rate-setting mechanism under a 35-year Franchise Agreement with the City of Cornwall expiring in 2033 and, therefore, is exempt from many aspects of the above Acts. The rate-setting mechanism is based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth, customer growth and premises vacancies.

Caribbean Utilities

Caribbean Utilities operates under T&D and generation licences from the Government of the Cayman Islands. The exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The non-exclusive generation licence is for a period of 21.5 years, expiring September 2029. The licences detail the role of the Electricity Regulatory Authority ("ERA"), which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism ("RCAM") and annually approves capital expenditures.

The licences contain the provision for an RCAM based on published consumer price indices. The ERA approved an increase in Caribbean Utilities' base customer electricity rates by 1.8%, effective June 1, 2013, due to the annual operation of the RCAM as a result of changes in the applicable consumer price indices and the utility's applicable targeted allowed rate of return on rate base assets ("ROA") for the 2013 rate adjustment. Customer electricity rates for 2013 translated into a targeted ROA in the range of 6.50% to 8.50% (2012 – 7.25% to 9.25%).

Fortis Turks and Caicos

FortisTCI and TCU operate under 50-year licences expiring in 2037 and 2036, respectively. Among other matters, the licences describe how electricity rates are set by the Government of the Turks and Caicos Islands, using a future test year, in order to provide the utilities with an allowed ROA of 17.50% for FortisTCI and 15% for TCU (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall").

Annual submissions are made to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2013 calculated the combined Allowable Operating Profit, inclusive of TCU, for 2013 to be $35 million (US$34 million) and the combined Cumulative Shortfall, inclusive of TCU, at December 31, 2013 to be $143 million (US$134 million). The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses.

The achieved ROAs at the utilities have been significantly lower than those allowed under the licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

3. Summary of Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP"), which for regulated public utilities include specific accounting guidance for regulated operations, as outlined in Note 2 and the following summary of significant accounting policies.

All amounts presented are in Canadian dollars unless otherwise stated.

Basis of Presentation

The consolidated financial statements reflect the Corporation's investments in its subsidiaries on a consolidated basis, with the equity method used for entities in which Fortis has significant influence, but not control. All material intercompany transactions have been eliminated in the consolidated financial statements.

An evaluation of subsequent events through to March 13, 2014, the date these consolidated financial statements were approved by the Board of Directors of Fortis ("Board of Directors"), was completed to determine whether the circumstances warranted recognition and disclosure of events or transactions in the consolidated financial statements as at December 31, 2013.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of uncollectible accounts receivable balances. Fortis and each of its subsidiaries maintain an allowance for doubtful accounts that is estimated based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy and economic conditions. Interest is charged on accounts receivable balances that have been outstanding for more than 21 to 30 days. Accounts receivable are charged-off in the period in which the receivable is deemed uncollectible.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Inventories

Inventories, consisting of gas and fuel in storage, and materials and supplies, are measured at the lower of average cost and market value.

Utility Capital Assets

Utility capital assets are recorded at cost less accumulated depreciation, with the following exceptions for rate-setting purposes: (i) utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost; (ii) utility capital assets of Caribbean Utilities are stated on the basis of appraised values as at November 30, 1984, with subsequent additions at cost; and (iii) utility capital assets of Fortis Turks and Caicos are stated at appraised values as at September 1986 for FortisTCI and as at April 1986 for TCU. Subsequent additions at Fortis Turks and Caicos are at cost, including the distribution systems on Middle, North and South Caicos, Grand Turk and Salt Cay, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by licences for US$4.00, in aggregate, as valued in the books of the utilities.

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being amortized annually by an amount equal to the charge for depreciation provided on the related assets.

FortisOntario and Fortis Turks and Caicos recognize non-asset retirement obligation ("non-ARO") removal costs, net of salvage proceeds, in earnings in the period incurred. Caribbean Utilities recognizes non-ARO removal costs in utility capital assets.

Notes to Consolidated Financial Statements

For the years ended December 31, 2013 and 2012

3. Summary of Significant Accounting Policies (cont'd)

Utility Capital Assets (cont'd)

Each of the FortisBC Energy companies, Central Hudson, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-ARO removal costs in depreciation, as required by their respective regulator, with the amount provided for in depreciation recorded as a long-term regulatory liability (Note 7 *(xvii)*). Actual non-ARO removal costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. During 2013 non-ARO removal costs of $73 million (2012 – $62 million) were accrued by the above-noted utilities as part of depreciation, and actual non-ARO removal costs of $14 million (2012 – $16 million), net of salvage proceeds, were incurred and recognized against the long-term regulatory liability (Note 7 *(xvii)*).

As permitted by the regulator, FortisBC Electric records actual non-ARO removal costs, net of salvage proceeds, against accumulated depreciation as incurred. During 2013 actual non-ARO removal costs of approximately $1 million (2012 – $4 million), net of salvage proceeds of less than $1 million (2012 – less than $1 million), were incurred at FortisBC Electric.

Utility capital assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of utility capital assets, any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation by Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gains or losses charged to accumulated depreciation will be reflected in future depreciation expense when they are refunded or collected in customer gas and electricity rates. The loss charged to accumulated depreciation in 2013 was approximately $11 million (2012 – $20 million).

The FortisBC Energy companies record any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets in a regulatory deferral account for recovery from customers in future rates, subject to regulatory approval (Note 7 *(viii)*).

At FortisOntario and Fortis Turks and Caicos, the regulatory authorities require that any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets be recognized immediately in earnings.

As required by their respective regulator, the FortisBC Energy companies, Central Hudson, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities, Fortis Turks and Caicos, and FortisOntario prior to 2013, capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator.

As required by their respective regulator, the FortisBC Energy companies, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities include in the cost of utility capital assets both a debt and an equity component in the allowance for funds used during construction ("AFUDC"). The debt component of AFUDC is reported as a reduction of finance charges (Note 25) and the equity component of AFUDC is reported as other income, net (Note 24). Both components of AFUDC are charged to earnings through depreciation expense over the estimated service lives of the applicable utility capital assets. AFUDC is calculated in a manner as prescribed by the respective regulator.

At FortisAlberta the cost of utility capital assets also include Alberta Electric System Operator ("AESO") contributions, which are investments required by FortisAlberta to partially fund the construction of transmission facilities.

As approved by the regulator, FEVI has reduced the amounts reported for utility capital assets by the amount of government loans received in connection with the construction and operation of the Vancouver Island natural gas pipeline. As the loans are repaid and replaced with non-government loans, FEVI increases both utility capital assets and long-term debt (Notes 15 and 35).

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets. When put into service, the inventories are depreciated using the straight-line method based on the estimated service lives of the capital assets to which they are added.

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred, while replacements and betterments which extend the useful lives are capitalized.

Utility capital assets are being depreciated using the straight-line method based on the estimated service lives of the utility capital assets. Depreciation rates for 2013 ranged from 1.3% to 43.2% (2012 – 1.3% to 43.2%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, for 2013 was 3.3% (2012 – 3.3%).

The service life ranges and weighted average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows:

	2013		2012	
(Years)	Service Life Ranges	Weighted Average Remaining Service Life	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Gas	7–85	39	4–68	36
Electricity	5–80	31	5–65	27
Transmission				
Gas	8–70	38	6–70	39
Electricity	20–70	31	20–65	26
Generation	4–75	30	5–75	31
Other	3–70	8	3–70	9

Non-Utility Capital Assets

Non-utility capital assets, which include office buildings, shopping malls, hotels, land, construction in progress, and related equipment and tenant inducements, are recorded at cost less accumulated depreciation, where applicable. Buildings are depreciated using the straight-line method over an estimated useful life of 60 years. Tenant inducements are depreciated over the initial terms of the leases to which they relate, except where a writedown is required to reflect permanent impairment. The lease terms vary to a maximum of 20 years. Equipment is depreciated on a straight-line basis over a range of 2 to 25 years.

Maintenance and repairs are charged to earnings in the period incurred, while replacements and betterments which extend the useful lives are capitalized.

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Included as capital leases are any arrangements that qualify as leases by conveying the right to use a specific asset.

Capital leases are depreciated over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case capital leases are depreciated over the estimated service life of the underlying asset. Where the regulator has approved recovery of the arrangements as operating leases for rate-setting purposes that qualify as capital leases for financial reporting purposes, the timing of the expense recognition related to the lease is modified to conform with the rate-setting process.

Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. The cost of intangible assets at the Corporation's regulated subsidiaries includes amounts for AFUDC and allocated overhead, where permitted by the respective regulators. Costs incurred to renew or extend the term of an intangible asset are capitalized and amortized over the new term of the intangible asset. Intangible assets are comprised of computer software costs; land, transmission and water rights; franchise fees; and customer contracts.

The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually, either individually or at the reporting unit level, if they are held in a regulated utility. Such intangible assets are not amortized. Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights at FEI, FEVI and FortisBC Electric. An intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

In testing indefinite-lived intangible assets for impairment, the Corporation has the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50% or more likely to be greater than the carrying value, calculation of fair value would not be required.

For the years ended December 31, 2013 and 2012

3. *Summary of Significant Accounting Policies (cont'd)*

Intangible Assets (cont'd)

Impairment testing for indefinite-lived intangible assets is carried out at the reporting unit level at the regulated utilities. A fair rate of return on the indefinite-lived intangible assets is provided through customer gas and electricity rates as approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of the indefinite-lived intangible assets is below its carrying value. No such event or change in circumstances occurred during 2013 or 2012 and there were no impairment provisions required in either year.

For its annual testing of impairment for indefinite-lived intangible assets, Fortis uses the approach for the annual testing for goodwill impairment as disclosed in this Note under "Goodwill".

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets and are assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the respective regulator.

Amortization rates for 2013 ranged from 1.6% to 51.0% (2012 – 1.5% to 43.0%). The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows:

	2013		2012	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**5–10**	**5**	5–10	5
Land, transmission and water rights	**31–75**	**38**	31–75	35
Franchise fees, customer contracts and other	**10–100**	**25**	10–100	23

Intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization by Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gain or loss charged to accumulated amortization will be reflected in future amortization costs when it is refunded or collected in customer gas and electricity rates.

The FortisBC Energy companies record any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets in a regulatory deferral account for recovery from, or refund to, customers in future rates, subject to regulatory approval (Note 7 *(viii)*).

At FortisOntario and Fortis Turks and Caicos, the regulatory authorities require that any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets be recognized immediately in earnings.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility and non-utility capital assets, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the consolidated financial statements as a result of asset impairments for the years ended December 31, 2013 and 2012.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash flow stream, such an asset is tested individually and impairment is recorded if the future net cash flows are no longer sufficient to recover the carrying value of the generating facility.

Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair rate of return, is provided through customer gas and electricity rates approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

Fortis performs an annual internal quantitative assessment for each reporting unit and, for those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) where the excess of estimated fair value over carrying value, as determined by an independent external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an independent external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an independent external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each reporting unit estimated by an independent external consultant once every three years.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit is below its carrying value. No such event or change in circumstances occurred during 2013 or 2012 and no impairment provisions were required in either year.

In calculating goodwill impairment, Fortis determines those reporting units that will have fair value estimated by an independent external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, then a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, is also performed by an independent external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, including retirement allowances and supplemental retirement plans for certain executive employees, and defined contribution pension plans, including group Registered Retirement Savings Plans ("RRSPs") for employees. The projected benefit obligation and the value of pension cost associated with the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and expected retirement ages of employees. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments.

With the exception of the FortisBC Energy companies and Newfoundland Power, pension plan assets are valued at fair value for the purpose of determining pension cost. At the FortisBC Energy companies and Newfoundland Power, pension plan assets are valued using the market-related value for the purpose of determining pension cost, where investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of the projected benefit obligation and the fair value of plan assets (the market-related value of plan assets at the FortisBC Energy companies and Newfoundland Power) at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of defined benefit pension plans, measured as the difference between the fair value of the plan assets and the benefit obligation, is recognized on the Corporation's consolidated balance sheet.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made.

Any difference between pension cost recognized under US GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 7 *(ii)*).

For the years ended December 31, 2013 and 2012

3. Summary of Significant Accounting Policies (cont'd)

Employee Future Benefits (cont'd)

At the FortisBC Energy companies, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power and FortisOntario, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 7 *(ii)*). At Fortis, FHI, Maritime Electric and Caribbean Utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans are recognized in accumulated other comprehensive income.

The costs of the defined contribution pension plans are expensed as incurred.

OPEB Plans
The Corporation, the FortisBC Energy companies, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario also offer OPEB plans through defined benefit plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The accumulated benefit obligation and the cost associated with OPEB plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan performance, salary escalation, expected retirement ages of employees and health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected OPEB payments.

The excess of any cumulative net actuarial gain or loss over 10% of the accumulated benefit obligation and the fair value of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of OPEB plans, measured as the difference between the fair value of the plan assets and the benefit obligation, is recognized on the Corporation's consolidated balance sheet.

As approved by the regulator, the cost of OPEB plans at FortisAlberta is recovered in customer rates based on the cash payments made.

With the exception of FortisAlberta, as discussed below, any difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 7 *(ii)*).

At FortisAlberta, the difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates does not meet the criteria for deferral account treatment and, therefore, FortisAlberta recognizes in earnings the cost associated with its OPEB plan as actuarially determined, rather than as approved by the regulator. Unamortized OPEB plan balances at FortisAlberta related to net actuarial gains and losses and past service costs are recognized as a component of other comprehensive income.

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its 2002 Stock Option Plan ("2002 Plan"), 2006 Stock Option Plan ("2006 Plan") and 2012 Stock Option Plan ("2012 Plan") (Note 23). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and each grant is amortized as a single award evenly over the four-year vesting period of the options granted. The offsetting entry is an increase to additional paid-in capital for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise, the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock. An exercise of options below the current market price of the Corporation's common shares has a dilutive effect on the Corporation's consolidated capital stock and shareholders' equity. Fortis satisfies stock option exercises by issuing common shares from treasury.

The Corporation also records the liabilities associated with its Directors' Deferred Share Unit ("DSU") and Performance Share Unit ("PSU") Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU and PSU liabilities is based on the Corporation's common share closing price at the end of each reporting period. The fair value of the PSU liability is also based on expected payout based on historical performance in accordance with defined metrics of each grant, where applicable, and management's best estimate.

Foreign Currency Translation

The assets and liabilities of the Corporation's foreign operations, all of which have a US dollar functional currency, are translated at the exchange rate in effect as at the balance sheet date. The reporting currency of Central Hudson, Caribbean Utilities, Fortis Turks and Caicos, BECOL, FortisUS Energy and Griffith is the US dollar. The exchange rate in effect as at December 31, 2013 was US$1.00=CDN$1.06 (December 31, 2012 – US$1.00=CDN$1.00). The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive loss until the foreign subsidiary is sold, substantially liquidated or evaluated for impairment in anticipation of disposal. Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate in effect during the reporting period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are accumulated as a separate component of shareholders' equity within accumulated other comprehensive loss and the current period change is recorded in other comprehensive income.

Effective June 20, 2011, as a result of the expropriation of Belize Electricity by the GOB, the Corporation's asset associated with its previous investment in Belize Electricity (Notes 9, 34 and 36) does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity are recognized in earnings.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recognized in earnings.

Derivative Instruments and Hedging Activities

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates, and fuel, electricity and natural gas prices through the use of derivative instruments. The Corporation does not hold or issue derivative instruments for trading purposes and generally limits the use of derivative instruments to those that qualify as accounting or economic hedges. As at December 31, 2013, the Corporation's derivative instruments primarily consisted of electricity swap contracts, gas swap and option contracts and gas purchase contract premiums (Note 32).

Mark-to-market is the default accounting treatment for all derivative instruments unless they qualify, and are designated, for one of the elective accounting treatments. Mark-to-market requires the derivative instrument to be recorded at fair value with changes in fair value recognized in earnings. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis. The elective accounting treatments include: (i) cash flow hedges; (ii) fair value hedges; and (iii) normal purchase normal sale arrangements.

The Corporation continually assesses its contracts, including its PPAs, to determine whether they meet the criteria of a derivative and, if so, whether they qualify for elective accounting treatment.

As at December 31, 2013, the Corporation's hedging relationships primarily consisted of electricity swap contracts, gas swap and option contracts, gas purchase contract premiums and US dollar borrowings.

Electricity swap contracts and natural gas derivatives are used by Central Hudson to minimize commodity price volatility for electricity and natural gas purchases for the Company's full-service customers by fixing the effective purchase price for the defined commodities.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the FortisBC Energy companies have floating, rather than fixed, prices. Any change in the fair value of the natural gas derivatives, whether or not the derivatives are in qualifying and designated hedging relationships, is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

The Corporation is required to bifurcate embedded derivatives from their host instruments and account for them as free-standing derivative instruments if they meet specified criteria.

The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The Corporation has designated its corporately issued US dollar long-term debt as a hedge of the foreign exchange risk related to its net investments in foreign subsidiaries. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which gains and losses are also recognized in other comprehensive income.

3. Summary of Significant Accounting Policies (cont'd)

Income Taxes

The Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not to be realized. The deferred income tax assets and liabilities are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the respective regulator, the FortisBC Energy companies, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax is recovered or refunded in current customer rates, as prescribed by the respective regulator. Therefore, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. These utilities recognize an offsetting regulatory asset or liability for the amount of deferred income taxes that are expected to be collected or refunded in customer rates once income taxes become payable or receivable (Note 7 *(i)*).

For regulatory reporting purposes, the capital cost allowance pool for certain utility capital assets at FortisAlberta is different from that for legal entity corporate income tax filing purposes. In a future reporting period, yet to be determined, the difference may result in higher income tax expense than that recognized for regulatory rate-setting purposes and collected in customer rates.

Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the GOB for the terms of its 50-year PPAs.

Any difference between the income tax expense recognized under US GAAP and that recovered from customers in current rates that is expected to be recovered from customers in future rates, is subject to deferral account treatment (Note 7 *(i)*).

The Corporation intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, the Corporation does not provide for deferred income taxes on temporary differences related to investments in foreign subsidiaries. As at December 31, 2013, temporary differences related to investments in foreign subsidiaries were approximately $334 million (December 31, 2012 – $294 million). It is impractical to estimate the amount of income tax that might be payable if a reversal of temporary differences occurred. Canada has entered into Tax Information Exchange Agreements ("TIEAs") with Bermuda, the Cayman Islands and the Turks and Caicos Islands. Consequently, earnings from the Corporation's foreign subsidiaries operating in these regions, subsequent to 2010, can be repatriated to Canada on a tax-free basis and, therefore, are not included in the amount of temporary differences noted above, as no taxes are payable on these earnings. When a TIEA is entered into with Belize, earnings from the Corporation's operations in Belize (i.e., BECOL) can also be repatriated to Canada on a tax-free basis. Negotiations between the Government of Canada and the GOB commenced in June 2010.

Tax benefits associated with income tax positions taken, or expected to be taken, in an income tax-return are recognized only when the more likely than not recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement. The difference between a tax position taken, or expected to be taken, and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Income tax interest and penalties are expensed as incurred and included in income tax expense. At FortisAlberta investment tax credits are deducted from the related assets and are recognized as a reduction of income tax expense as the Company becomes taxable for rate-setting purposes.

Sales Taxes

In the course of its operations, the Corporation and its subsidiaries collect sales taxes from its customers. When customers are billed, a current liability is recognized for the sales taxes included on customers' bills. The liability is settled when the taxes are remitted to the appropriate government authority. The Corporation's revenue excludes sales taxes.

For regulatory reporting purposes, Central Hudson records receipt tax revenue and expenses collected on behalf of applicable government authorities on a gross basis. The amounts included in 2013 in both revenue and expenses was approximately $4 million.

Revenue Recognition

Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority and is generally bundled to include service associated with generation and T&D, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

Revenue from the sale of gas and electricity by the Corporation's regulated utilities is generally recognized on an accrual basis. Gas and electricity consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, with the exception of certain electricity customers at Central Hudson, as approved by the regulator. As at December 31, 2013, approximately $14 million (US$13 million) in unbilled revenue at Central Hudson associated with these electricity customers was not accrued.

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with AESO and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. In 2013, FortisAlberta was not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers were deferred to be recovered from, or refunded to, customers in future rates (Note 7 *(xviii)*). For 2012, however, the regulator did not approve the deferral of transmission volume variances and FortisAlberta was subject to volume risk on actual transmission costs relative to those charged to customers based on forecast volumes and prices.

FortisOntario's regulated operations primarily consist of the operations of Cornwall Electric, Canadian Niagara Power and Algoma Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power and Algoma Power are not bundled. At Canadian Niagara Power and Algoma Power, the cost of power and/or transmission is a flow through to customers and revenue associated with the recovery of these costs is tracked and recorded separately. The amount of transmission revenue tracked separately at Canadian Niagara Power and Algoma Power is not significant in relation to the consolidated revenue of the Corporation.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements.

Non-utility revenue is recognized when services are provided or products are delivered to customers. Specifically, real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recognized in the month that it is earned at rates in accordance with lease agreements.

The leases are primarily of a net nature, with tenants paying basic rent plus a pro-rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenants' sales. Expenses recovered from tenants are recorded as revenue on an accrual basis. Base rent and the escalation of lease rates included in long-term leases are recognized in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations

Asset-retirement obligations ("AROs"), including conditional AROs, are recorded as a liability at fair value, with a corresponding increase to utility or non-utility capital assets. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of AROs is based on an estimate of the present value of expected future cash outlays reflecting a range of possible outcomes, discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to reflect the passage of time and any changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities.

As at December 31, 2013, FortisBC Electric and Central Hudson recognized a total of approximately $3 million in AROs (December 31, 2012 – $3 million), which have been classified as long-term other liabilities (Note 17), with the offset to utility capital assets. Changes in the obligations due to the passage of time are recognized as a regulatory asset using the effective interest method.

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

3. Summary of Significant Accounting Policies (cont'd)

Asset-Retirement Obligations (cont'd)

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights-of-way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of the fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

Disclosures About Offsetting Assets and Liabilities

Effective January 1, 2013, the Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 210, *Balance Sheet – Disclosures About Offsetting Assets and Liabilities* as outlined in Accounting Standards Update ("ASU") No. 2011-11 and ASU No. 2013-01. The amendments improve the transparency of the effect or potential effect of netting arrangements on a company's financial position by expanding the level of disclosures required by entities for such arrangements. The above-noted amendments were applied retrospectively and did not materially impact the Corporation's consolidated financial statements for 2013.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

Effective January 1, 2013, the Corporation adopted the amendments to ASC Topic 220, *Other Comprehensive Income – Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income* ("AOCI") as outlined in ASU No. 2013-02. The amendments improve the reporting of reclassifications out of AOCI and require entities to report, in one place, information about reclassifications out of AOCI and to present details of the reclassifications in the disclosure for changes in AOCI balances. The amendments were applied by the Corporation prospectively commencing on January 1, 2013 and did not materially impact the Corporation's consolidated financial statements for 2013.

Use of Accounting Estimates

The preparation of the consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility and Non-Utility Capital Assets, Intangible Assets, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition and Asset-Retirement Obligations, and in Notes 7 and 37.

4. Future Accounting Pronouncements

Obligations Resulting from Joint and Several Liability Arrangements

In February 2013 the Financial Accounting Standards Board ("FASB") issued ASU No. 2013-04, *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date*. The objective of this update is to provide 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. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied retrospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Parent's Accounting for the Cumulative Translation Adjustment

In March 2013 FASB issued ASU No. 2013-5, *Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity*. This update applies to the release of the cumulative translation adjustment into net earnings 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 within a foreign entity. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Presentation of an Unrecognized Tax Benefit

In July 2013 FASB issued ASU No. 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*. This amendment provides guidance on the presentation of unrecognized tax benefits when net operating loss carryforwards, similar tax losses or tax credit carryforwards exist, and is intended to better reflect the manner in which an entity would settle any additional income taxes that would result from the disallowance of a tax position when net operating loss carryforwards, similar tax losses or tax credit carryforwards exist. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

5. Accounts Receivable

(in millions)	**2013**	2012
Accounts receivable – trade	**$ 701**	$ 544
Allowance for doubtful accounts	**(19)**	(19)
Income tax receivable	**–**	11
Other	**50**	51
	$ 732	$ 587

Other accounts receivable as at December 31, 2013 and 2012 consisted mainly of customer billings for non-core services, collateral deposits for gas purchases and residential tax credits at the FortisBC Energy companies. Other accounts receivable also include the fair value of derivatives at Central Hudson (Notes 32 and 33).

6. Inventories

(in millions)	**2013**	2012
Gas and fuel in storage	**$ 116**	$ 115
Materials and supplies	**27**	18
	$ 143	$ 133

7. Regulatory Assets and Liabilities

Based on previous, existing or expected regulatory orders or decisions, the Corporation's regulated utilities have recorded the following amounts that are expected to be recovered from, or refunded to, customers in future periods.

(in millions)	**2013**	2012	**Remaining recovery period (Years)**
Regulatory assets			
Deferred income taxes *(i)*	**$ 833**	$ 713	To be determined
Employee future benefits *(ii)*	**440**	498	Various
Rate stabilization accounts *(iii)*	**85**	105	Various
Deferred lease costs – FortisBC Electric *(iv)*	**76**	77	30–43
Deferred energy management costs *(v)*	**76**	50	1–15
MGP site remediation deferral *(vi)*	**47**	–	To be determined
Deferred operating overhead costs *(vii)*	**43**	32	Various
Deferred net losses on disposal of utility capital assets and intangible assets *(viii)*	**35**	27	18
Income taxes recoverable on OPEB plans *(ix)*	**24**	23	Various
Customer Care Enhancement Project cost deferral *(x)*	**21**	24	6–7
Carrying charges – employee future benefits *(xi)*	**14**	–	Various
Whistler pipeline contribution deferral *(xii)*	**13**	14	46
Alternative energy projects cost deferral *(xiii)*	**11**	18	To be determined
Deferred development costs for capital projects *(xiv)*	**9**	10	18
Replacement energy deferral – Point Lepreau *(xv)*	**–**	47	–
Other regulatory assets *(xvi)*	**95**	62	Various
Total regulatory assets	**1,822**	1,700	
Less: current portion	**(150)**	(185)	1
Long-term regulatory assets	**$ 1,672**	$ 1,515	
Regulatory liabilities			
Non-ARO removal cost provision *(xvii)*	**$ 563**	$ 486	To be determined
Rate stabilization accounts *(iii)*	**177**	163	Various
AESO charges deferral *(xviii)*	**73**	44	1–4
Employee future benefits *(ii)*	**55**	–	Various
Deferred income taxes *(i)*	**45**	12	To be determined
Customer and community benefits obligation *(xix)*	**23**	–	To be determined
Meter reading and customer service variance deferral *(xx)*	**17**	6	To be determined
Carrying charges – employee future benefits *(xi)*	**16**	–	Various
Rate base impact of tax repair project *(xxi)*	**13**	–	To be determined
Other regulatory liabilities *(xxii)*	**60**	42	Various
Total regulatory liabilities	**1,042**	753	
Less: current portion	**(140)**	(72)	1
Long-term regulatory liabilities	**$ 902**	$ 681	

Description of the Nature of Regulatory Assets and Liabilities

(i) Deferred Income Taxes

The Corporation recognizes deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Included in deferred income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates. The deferred income taxes on regulatory assets and liabilities are the result of the application of ASC Topic 740, *Income Taxes*. The regulatory asset and liability balances are expected to be recovered from, or refunded to, customers in future rates when the income taxes become payable or receivable. As at December 31, 2013, $170 million (December 31, 2012 – $115 million) in regulatory assets for deferred income taxes was not subject to a regulatory return.

(ii) Employee Future Benefits

The regulatory asset and liability associated with employee future benefits includes the actuarially determined unamortized net actuarial losses, past service costs and transitional obligations associated with defined benefit pension and OPEB plans maintained by the Corporation's regulated utilities, which are expected to be recovered from, or refunded to, customers in future rates (Note 28).

At the Corporation's regulated utilities, as approved by the respective regulators, differences between defined benefit pension and OPEB plan costs recognized under US GAAP and those which are expected to be recovered from, or refunded to, customers in future rates are subject to deferral account treatment and have been recognized as a regulatory asset or liability. These amounts would otherwise be recognized in accumulated other comprehensive loss on the consolidated balance sheet.

As at December 31, 2013, regulatory assets of approximately $125 million associated with employee future benefits were not subject to a regulatory return (December 31, 2012 – $94 million). As at December 31, 2013, regulatory liabilities of approximately $55 million associated with employee future benefits were not subject to a regulatory return (December 31, 2012 – nil).

(iii) Rate Stabilization Accounts

Rate stabilization accounts associated with the Corporation's regulated electric utilities (Central Hudson, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities, and Fortis Turks and Caicos) are recovered from, or refunded to, customers in future rates, as approved by the respective regulatory authority. Rate stabilization accounts primarily mitigate the effect on earnings of variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level.

At FortisBC Electric, the flow-through variance regulatory liability includes variances between actual electricity revenue and purchased power costs and those forecast in determining customer electricity rates. In addition, the regulatory flow-through balance approved for deferral as a regulatory liability includes amounts related to the GCOC Proceeding stage one decision that decreased the Company's interim allowed ROE and is expected to be approved by the BCUC for settlement in 2014 and 2015 as reductions to 2014 and 2015 electricity revenue. In 2012, the flow-through variance regulatory liability at FortisBC Electric included the flow through back to customers for the refundable portion of the over collection of revenue requirements based on 2012 interim customer rates as compared to the final 2012 customer rates approved by the BCUC.

At Central Hudson, RDMs minimize the earnings impact resulting from reduced energy consumption as energy-efficiency programs are implemented. The RDMs allow the Company to recognize electric and gas revenue at the levels approved in rates for most of Central Hudson's customer base.

At Newfoundland Power, the PUB has ordered the provision of a weather normalization account to adjust for the effect of variations in weather conditions when compared to long-term averages. The weather normalization account reduces the volatility in Newfoundland Power's year-to-year earnings that would otherwise result from fluctuations in revenue and purchased power.

As at December 31, 2013, approximately $53 million and $37 million of the electric utilities' rate stabilization accounts are expected to be recovered from, or refunded to, customers within one year and, as a result, are classified as current regulatory assets and liabilities, respectively (December 31, 2012 – approximately $45 million and $28 million, respectively).

As at December 31, 2013, $56 million of the balance of rate stabilization accounts in a receivable position at Central Hudson, Newfoundland Power, FortisOntario and Caribbean Utilities was not subject to a regulatory return (December 31, 2012 – $49 million).

7. *Regulatory Assets and Liabilities (cont'd)*

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(iii) Rate Stabilization Accounts (cont'd)

Rate stabilization accounts associated with the Corporation's regulated gas utilities (the FortisBC Energy companies and Central Hudson) are recovered from, or refunded to, customers in future rates, as approved by the respective regulatory authority. Rate stabilization accounts primarily mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather, natural gas cost volatility and changes in the fair value of natural gas commodity derivative instruments.

At FEI, rate stabilization mechanisms are in place to: (i) accumulate the margin impact of variations in the actual versus forecast gas volumes consumed by residential and commercial customers; (ii) accumulate differences between actual natural gas costs and forecast natural gas costs; and (iii) accumulate the changes in fair value of natural gas derivative instruments. At FEVI, rate stabilization mechanisms are in place to: (i) mitigate the effect on earnings of natural gas cost volatility; (ii) accumulate the changes in fair value of natural gas derivative instruments; and (iii) accumulate differences between revenue collected from customers and actual COS, excluding variances from forecast related to operation and maintenance expenses.

As at December 31, 2013, approximately $24 million and $28 million of the gas utilities' rate stabilization accounts are expected to be recovered from, or refunded to, customers within one year and, as a result, are classified as current regulatory assets and liabilities, respectively (December 31, 2012 – approximately $48 million and $18 million, respectively).

(iv) Deferred Lease Costs – FortisBC Electric

The depreciation of FortisBC Electric's Brilliant Power Purchase Agreement ("BPPA") asset under capital lease and interest expense associated with the BPPA capital lease obligation are not being fully recovered by FortisBC Electric in current customer rates, since those rates include only the cash payments set out under the BPPA. The regulatory asset balance as at December 31, 2013 includes $70 million (December 31, 2012 – $63 million) of deferred BPPA lease costs that are expected to be recovered from customers in future rates over the term of the BPPA lease, which ends in 2056.

FortisBC Electric also defers lease costs associated with the Brilliant Terminal Station ("BTS"). The capital cost of the BTS, the cost of financing the BTS obligation and the related operating expense are not being fully recovered by FortisBC Electric in current customer rates, since those rates include only the cash payments set out under the BTS lease. The regulatory asset balance as at December 31, 2013 includes $6 million (December 31, 2012 – $6 million) of deferred lease costs related to the BTS that are expected to be recovered from customers in future rates over the term of the BTS lease.

In 2013, of the $29 million (2012 – $29 million) of interest expense related to the BPPA and BTS capital lease obligations and the $6 million (2012 – $6 million) of depreciation expense related to the BPPA and BTS assets under capital lease, a total of $25 million (2012 – $25 million) was recognized in energy supply costs and $3 million (2012 – $3 million) was recognized in operating expenses, respectively, as approved by the regulator, with the balance of $7 million (2012 – $7 million) deferred as a regulatory asset (Note 16).

In 2013 FortisBC Electric exercised its tenant's option per the lease agreement to purchase the Trail office building. Accordingly, the finance obligation, regulatory asset and utility capital asset, all recognized as a result of assessing the original lease arrangement as a failed sale-leaseback, have been reclassified on the consolidated balance sheet as utility capital assets as at December 31, 2013 (Note 16).

FortisBC Electric's deferred lease costs are not subject to a regulatory return.

(v) Deferred Energy Management Costs

The FortisBC Energy companies, FortisBC Electric, Central Hudson, Newfoundland Power and Maritime Electric provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, these regulated utilities have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from 2 to 15 years. This regulatory asset represents the unamortized balance of the energy management costs.

(vi) MGP Site Remediation Deferral

As approved by the regulator, Central Hudson is permitted to defer for future recovery from its customers the difference between actual costs for MGP site investigation and remediation and the associated rate allowances. Central Hudson's MGP site remediation costs are not subject to a regulatory return.

(vii) Deferred Operating Overhead Costs

As approved by the regulator, FortisAlberta has deferred certain operating overhead costs. The deferred costs are expected to be collected in future customer rates over the lives of the related utility capital assets.

(viii) Deferred Net Losses on Disposal of Utility Capital Assets and Intangible Assets

As approved by the regulator, gains and/or losses on the retirement or disposal of utility capital assets and intangible assets at the FortisBC Energy companies are recorded in a regulatory deferral account to be recovered from customers in future rates. The regulator approved the recovery in customer rates of the resulting regulatory asset over a period of 20 years, which commenced in 2012.

(ix) Income Taxes Recoverable on OPEB Plans

At the FortisBC Energy companies and FortisBC Electric, the regulator allows OPEB plan costs to be collected in customer rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. As approved by the regulator, the tax effect of this timing difference is deferred as a separate regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer rates.

(x) Customer Care Enhancement Project Cost Deferral

The Customer Care Enhancement Project cost deferral accumulated all incremental costs associated with the implementation of FEI's Customer Care Enhancement Project, which was substantially completed in January 2012. The regulator also approved deferral account treatment for variances from forecast for certain costs related to the customer care function. The regulatory asset is approved for recovery in customer rates over an eight-year period that commenced in 2012 and 2013 for costs deferred in each respective year.

(xi) Carrying Charges – Employee Future Benefits

As approved by the regulator, the difference between Central Hudson's defined benefit pension and OPEB plan costs recognized under US GAAP and those which are expected to be refunded to, or recovered from, customers in future rates are subject to deferral account treatment. As a result, a regulatory asset and regulatory liability have been recognized related to the Company's defined benefit pension and OPEB plans, respectively. The regulator allows Central Hudson to accrue carrying charges on the regulatory asset and liability balances associated with defined benefit pension and OPEB plans. The balance is not subject to a regulatory return.

(xii) Whistler Pipeline Contribution Deferral

The Whistler pipeline contribution deferral represents the capital contribution from FEWI to FEVI on completion of the natural gas pipeline to Whistler, as constructed by FEVI. The deferral is being recovered from FEWI's customers over a period of 50 years, which commenced in 2010, as approved by the regulator.

(xiii) Alternative Energy Projects Cost Deferral

The alternative energy projects cost deferral at the FortisBC Energy companies represents costs, net of revenue, associated with the investment in alternative energy solutions. The recovery period of the regulatory asset is to be determined by the regulator at a future time and is expected to be recovered from current and future alternative energy services customers.

(xiv) Deferred Development Costs for Capital Projects

Deferred development costs for capital projects include costs for projects under development at the FortisBC Energy companies that are subject to regulatory approval for recovery in future customer rates. The majority of the balance relates to the project cost overrun incurred on the conversion of FEWI customer appliances from propane to natural gas, for which FEWI received a decision from the BCUC allowing these additional costs to be deferred and collected in FEWI customer rates over a period of 20 years, which commenced in 2012.

(xv) Replacement Energy Deferral – Point Lepreau

The New Brunswick Power Point Lepreau nuclear generating station ("Point Lepreau") underwent a major refurbishment from 2008 through fall 2012. Maritime Electric had regulatory approval to defer the cost of incremental replacement energy related to Point Lepreau from 2008 through February 28, 2011, which totalled $47 million. Under the terms of the *PEI Energy Accord* and the *Accord Continuation Act*, the Government of PEI assumed, effective March 1, 2011, responsibility for the cost of incremental replacement energy and monthly operating and maintenance costs related to Point Lepreau during the remainder of the refurbishment period. In March 2013, the $47 million regulatory asset was assumed by the Government of PEI and collection from customers on behalf of the government began in the same period.

7. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xvi) Other Regulatory Assets

Other regulatory assets relate to all of the Corporation's regulated utilities. The balance is comprised of various items, each individually less than $10 million. As at December 31, 2013, $79 million (December 31, 2012 – $42 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2013, $44 million (December 31, 2012 – $21 million) of the balance was not subject to a regulatory return.

(xvii) Non-ARO Removal Cost Provision

As required by the respective regulator, depreciation rates at the FortisBC Energy companies, Central Hudson, FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to accrue for non-ARO removal costs. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. This regulatory liability represents amounts collected in customer electricity rates at the respective utilities in excess of incurred non-ARO removal costs.

(xviii) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenue collected for various items, such as transmission costs incurred and flowed through to customers, that are subject to deferral to be collected in future customer rates. To the extent that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be refunded in future customer rates. As at December 31, 2013, the regulatory liability primarily represented the over collection of costs. The settlement of the regulatory liability will be determined by the regulator in a future period.

(xix) Customer and Community Benefits Obligation

As approved by the PSC, Fortis committed to provide Central Hudson's customers and community with approximately US$50 million in financial benefits that would not have been realized in the absence of the acquisition (Note 29). These incremental benefits include: (i) US$35 million to cover expenses that would normally be recovered in customer rates; (ii) guaranteed savings to customers of more than US$9 million over five years resulting from the elimination of costs CH Energy Group would otherwise incur as a public company; and (iii) the establishment of a US$5 million Community Benefit Fund to be used for low-income customer and economic development programs for communities and residents of the Mid-Hudson River Valley. As a result, $41 million (US$40 million) in expenses were recognized in the second quarter of 2013 associated with the write-off of a $20 million (US$20 million) regulatory asset related to deferred storm costs and the recognition of a regulatory liability for customer and community benefits of $21 million (US$20 million) (Notes 24 and 29).

(xx) Meter Reading and Customer Service Variance Deferral

At the FortisBC Energy companies, variances between expenditures that are approved for recovery in customer rates and actual expenditures incurred for meter reading services and certain ongoing operating costs of the insourced activities related to the Customer Care Enhancement Project are permitted deferral account treatment, as approved by the regulator. The settlement of the regulatory liability will be determined by the regulator in a future period.

(xxi) Rate Base Impact of Tax Repair Project

Central Hudson maintains a tax repair project regulatory liability that represents accumulated tax refunds plus accrued carrying charges to be refunded to customers through future rates over a time period to be determined during Central Hudson's next rate hearing with the PSC.

(xxii) Other Regulatory Liabilities

Other regulatory liabilities relate to all of the Corporation's regulated utilities. The balance is comprised of various items, each individually less than $10 million. As at December 31, 2013, $51 million (December 31, 2012 – $14 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2013, $9 million (December 31, 2012 – $3 million) of the balance was not subject to a regulatory return.

8. Assets Held for Sale

In March 2014 CH Energy Group sold its non-regulated subsidiary, Griffith, for approximately US$70 million plus working capital (Note 38). As a result, the assets and liabilities of Griffith have been classified as held for sale on the consolidated balance sheet as at December 31, 2013 and the results of operations have been presented as discontinued operations on the consolidated statement of earnings. Assets and liabilities of Griffith as at December 31, 2013 are recorded at the lower of carrying value or fair value, less costs to sell.

The table below details the assets and liabilities held for sale.

(in millions)	**2013**
ASSETS	
Current assets	
Cash and cash equivalents	**$ 3**
Accounts receivable	**35**
Prepaid expenses	**4**
Inventories	**6**
Deferred income taxes	**1**
	49
Other assets	**1**
Non-utility capital assets	**11**
Intangible assets	**51**
Assets held for sale	**$ 112**
LIABILITIES	
Current liabilities	
Accounts payable and other current liabilities	**$ 27**
Deferred income taxes	**3**
	30
Other liabilities	**2**
Liabilities associated with assets held for sale	**$ 32**

The table below provides details on the results of the discontinued operations of Griffith.

(in millions)	**2013**
Revenue	**$ 143**
Earnings from discontinued operations before income taxes	**1**
Income tax expense	**(1)**
Earnings from discontinued operations, net of tax	**$ –**

9. Other Assets

(in millions)	**2013**	2012
Other asset – Belize Electricity *(Notes 34 and 36)*	**$ 108**	$ 104
Deferred financing costs	**51**	42
Deferred compensation plan assets *(Note 17)*	**15**	–
Supplemental Executive Retirement Plan assets *(Note 28)*	**14**	–
Long-term income tax receivable	**13**	13
Equity and cost investments	**10**	10
Subscription Receipts issue costs *(Note 18)*	**–**	13
Other	**35**	18
	$ 246	$ 200

9. Other Assets (cont'd)

As a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB and the consequential loss of control over the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. The book value of the Corporation's expropriated investment in Belize Electricity is classified as a long-term other asset. The asset is denominated in US dollars and has been translated into Canadian dollars at the exchange rate prevailing as at the balance sheet date. Effective June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity does not qualify for hedge accounting and, as a result, a foreign exchange gain of approximately $6 million was recognized in earnings in 2013 (2012 – foreign exchange loss of $2 million) (Note 24).

Central Hudson provides additional post-employment benefits through both a deferred compensation plan for Directors and Officers of the Company, as well as a Supplemental Executive Retirement Plan ("SERP"). Since both plans are considered non-qualified plans under the *Employee Retirement Income Security Act of 1974*, the assets are reported separately from the related liabilities (Notes 17 and 28). The assets of the plans are held in trust and funded mostly through the use of trust-owned life insurance policies and mutual funds. A portion of the SERP plan assets is invested in corporate-owned life insurance policies.

Other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable. Other assets also include the fair value of derivatives at Central Hudson (Notes 32 and 33).

10. Utility Capital Assets

2013

(in millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Distribution			
Gas	**$ 3,022**	**$ (805)**	**$ 2,217**
Electricity	**5,716**	**(1,526)**	**4,190**
Transmission			
Gas	**1,579**	**(462)**	**1,117**
Electricity	**1,382**	**(390)**	**992**
Generation	**1,462**	**(432)**	**1,030**
Other	**1,594**	**(536)**	**1,058**
Assets under construction	**881**	**–**	**881**
Land	**133**	**–**	**133**
	$ 15,769	**$ (4,151)**	**$ 11,618**

2012

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Gas	$ 2,595	$ (676)	$ 1,919
Electricity	4,488	(1,238)	3,250
Transmission			
Gas	1,489	(406)	1,083
Electricity	1,082	(293)	789
Generation	1,360	(367)	993
Other	1,233	(450)	783
Assets under construction	692	–	692
Land	114	–	114
	$ 13,053	$ (3,430)	$ 9,623

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electricity distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electricity transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

As at December 31, 2013, assets under construction are primarily associated with the Waneta Expansion.

The cost of utility capital assets under capital lease as at December 31, 2013 was $313 million (December 31, 2012 – $309 million) and related accumulated depreciation was $70 million (December 31, 2012 – $63 million).

11. Non-Utility Capital Assets

2013

(in millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Buildings	**$ 546**	**$ (95)**	**$ 451**
Equipment	**132**	**(62)**	**70**
Tenant inducements	**33**	**(25)**	**8**
Land	**72**	**–**	**72**
Assets under construction	**48**	**–**	**48**
	$ 831	**$ (182)**	**$ 649**

2012

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Buildings	$ 543	$ (85)	$ 458
Equipment	114	(52)	62
Tenant inducements	31	(23)	8
Land	72	–	72
Assets under construction	26	–	26
	$ 786	$ (160)	$ 626

12. Intangible Assets

2013

(in millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
Computer software	**$ 361**	**$ (193)**	**$ 168**
Land, transmission and water rights	**165**	**(32)**	**133**
Franchise fees, customer contracts and other	**16**	**(12)**	**4**
Assets under construction	**40**	**–**	**40**
	$ 582	**$ (237)**	**$ 345**

2012

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 320	$ (155)	$ 165
Land, transmission and water rights	141	(21)	120
Franchise fees, customer contracts and other	15	(12)	3
Assets under construction	37	–	37
	$ 513	$ (188)	$ 325

Included in the cost of land, transmission and water rights as at December 31, 2013 was $66 million (December 31, 2012 – $66 million) not subject to amortization.

12. Intangible Assets (cont'd)

Amortization expense related to intangible assets was $49 million for 2013 (2012 – $44 million). Amortization is estimated to average approximately $53 million annually for each of the next five years.

As at December 31, 2013, assets under construction primarily related to the Waneta Expansion.

13. Goodwill

(in millions)	**2013**	2012
Balance, beginning of year	**$ 1,568**	$ 1,565
Acquisition of CH Energy Group *(Note 29)*	**476**	–
Acquisition of City of Kelowna's electrical utility assets *(Note 29)*	**14**	–
Acquisition of Port Colborne distribution assets *(Note 29)*	**–**	4
Acquisition of TCU *(Note 29)*	**–**	1
Foreign currency translation impacts	**17**	(2)
Balance, end of year	**$ 2,075**	$ 1,568

Goodwill associated with the acquisitions of CH Energy Group, Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the reporting currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

14. Accounts Payable and Other Current Liabilities

(in millions)	**2013**	2012
Accounts payable – trade	**$ 463**	$ 498
Gas and fuel cost payable	**135**	111
Interest payable	**91**	85
Employee compensation and benefits payable	**104**	81
Dividends payable	**73**	64
Natural gas derivatives *(Notes 32 and 33)*	**15**	60
Income taxes payable	**9**	24
Defined benefit pension and OPEB plan liabilities *(Note 28)*	**7**	5
Other	**60**	38
	$ 957	$ 966

15. Long-Term Debt

(in millions)	Maturity Date	2013	2012
Regulated Utilities			
FortisBC Energy Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2012 – 10.71%)	2015 – 2016	**$ 275**	$ 275
Unsecured Debentures –			
5.95% weighted average fixed rate (2012 – 5.95%)	2029 – 2041	**1,620**	1,620
Government loan *(Notes 3 and 35)*	2014	**10**	4
Central Hudson			
Unsecured US Promissory Notes –			
4.51% weighted average fixed and variable rate	2014 – 2042	**521**	–
FortisAlberta			
Unsecured Debentures –			
5.31% weighted average fixed rate (2012 – 5.36%)	2014 – 2052	**1,459**	1,309
FortisBC Electric			
Secured Debentures –			
8.80% weighted average fixed rate (2012 – 8.80%)	2023	**25**	25
Unsecured Debentures –			
5.84% weighted average fixed rate (2012 – 5.84%)	2014 – 2050	**600**	600
Newfoundland Power			
Secured First Mortgage Sinking Fund Bonds –			
7.28% weighted average fixed rate (2012 – 7.66%)	2014 – 2043	**518**	453
Maritime Electric			
Secured First Mortgage Bonds –			
7.18% weighted average fixed rate (2012 – 7.18%)	2016 – 2061	**167**	167
FortisOntario			
Unsecured Senior Notes –			
6.11% weighted average fixed rate (2012 – 6.11%)	2018 – 2041	**104**	104
Caribbean Utilities			
Unsecured US Senior Loan Notes –			
5.43% weighted average fixed rate (2012 – 6.01%)	2014 – 2033	**233**	187
Fortis Turks and Caicos			
Unsecured:			
US Scotiabank (Turks and Caicos) Ltd. Loan –			
2.62% weighted average fixed and variable rate (2012 – 5.05%)	2014 – 2021	**17**	5
US First Caribbean International Bank loan –			
5.65% fixed rate	2015	**1**	5
Non-Regulated – Fortis Generation			
Secured: Mortgage – 9.44% fixed rate	n/a	**–**	1
Non-Regulated – Non-Utility			
Secured: First mortgages –			
7.03% weighted average fixed rate (2012 – 7.11%)	2014 – 2017	**47**	111
Secured: Senior Notes – 7.32% fixed rate	2019	**9**	11
Unsecured: US Promissory Notes –			
6.75% weighted average fixed rate	2014 – 2025	**29**	–
Corporate – Fortis and FHI			
Unsecured: Debentures –			
6.14% weighted average fixed rate (2012 – 6.14%)	2014 – 2039	**325**	326
Unsecured: US Senior Notes –			
4.93% weighted average fixed rate (2012 – 5.49%)	2014 – 2043	**931**	547
Long-term classification of credit facility borrowings *(Note 34)*		**313**	150
Total long-term debt *(Note 33)*		**7,204**	5,900
Less: Current installments of long-term debt		**(780)**	(159)
		$ 6,424	$ 5,741

For the years ended December 31, 2013 and 2012

15. Long-Term Debt (cont'd)

The purchase money mortgages of the FortisBC Energy companies are secured equally and rateably by a first fixed and specific mortgage and charge on FEI's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be issued is limited to $425 million.

As identified in the table above, certain long-term debt instruments issued by FortisBC Electric, Newfoundland Power, Maritime Electric and Fortis Properties are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the company to which the long-term debt is associated.

Covenants

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares, or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at December 31, 2013, the Corporation and its subsidiaries were in compliance with their debt covenants.

Regulated Utilities

The majority of the long-term debt instruments at the Corporation's regulated utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

In May 2013 Caribbean Utilities issued 15-year US$10 million 3.34% and 20-year US$40 million 3.54% unsecured notes. The net proceeds were used to repay short-term borrowings and to finance capital expenditures.

In September 2013 FortisAlberta issued 30-year $150 million 4.85% unsecured debentures. The net proceeds were used to repay credit facility borrowings, to fund capital expenditures and for general corporate purposes.

In November 2013 Newfoundland Power issued 30-year $70 million 4.805% first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings, which were incurred to fund capital expenditures, and for general corporate purposes.

In November and December 2013, Central Hudson issued 5-year US$30 million 2.45% and 15-year US$17 million 4.09% unsecured notes, respectively. The net proceeds were used to repay long-term debt and for general corporate purposes.

Corporate – Fortis and FHI

The majority of the unsecured debentures and all of the US senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

In October 2013 the Corporation issued 10-year US$285 million 3.84% and 30-year US$40 million 5.08% unsecured notes. The net proceeds were used to repay a portion of the Corporation's US dollar-denominated credit facility borrowings incurred to initially finance a portion of the CH Energy Group acquisition.

Repayment of Long-Term Debt

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

Year	Subsidiaries *(in millions)*	Corporate *(in millions)*	Total *(in millions)*
2014	$ 495	$ 285	$ 780
2015	103	–	103
2016	360	–	360
2017	79	–	79
2018	130	214	344
Thereafter	4,567	971	5,538

16. Capital Lease and Finance Obligations

Capital Lease Obligations

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant Plant located near Castlegar, British Columbia. FortisBC Electric operates and maintains the Brilliant Plant, under the BPPA which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Due to the fixed annual escalators, the interest expense on the capital lease obligation presently exceeds the required payments. The capital lease obligation will continue to increase through to 2024, and subsequently decrease for the remainder of the term when the required payments exceed the interest expense on the capital lease obligation. Approximately 94% of the output from the Brilliant Plant is being purchased by FortisBC Electric through the BPPA.

The BPPA capital lease obligation bears interest at a composite rate of 5.01%. Included in energy supply costs for 2013 was $25 million (2012 – $25 million) recognized in accordance with the BPPA, as approved by the BCUC (Note 7 *(iv)*).

FortisBC Electric also has a capital lease obligation with respect to the operation of the BTS, under an agreement which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 8.64%. Included in operating expenses for 2013 was $3 million (2012 – $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC (Note 7 *(iv)*).

The remaining capital lease obligations are held by the FortisBC Energy companies and are associated with various vehicle capital leases having terms that expire in 2014 through 2018.

Finance Obligations

In 2013 FortisBC Electric exercised its tenant's option per the lease agreement to purchase the Trail office building. Accordingly, the finance obligation, regulatory asset and utility capital asset, all recognized as a result of assessing the original lease arrangement as a failed sale-leaseback, have been reclassified on the consolidated balance sheet as utility capital assets at December 31, 2013 (Note 7 *(iv)*).

Between 2000 and 2005 FEI entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI from the municipalities. The natural gas distribution assets are considered to be integral equipment to real estate assets and, as such, the transactions have been accounted for as financing transactions. The proceeds from these transactions have been recognized as finance obligations on the consolidated balance sheet. Lease payments, net of the portion considered to be interest expense, reduce the finance obligations.

Obligations under the above-noted lease-in lease-out transactions at FEI have implicit interest at rates ranging from 7.20% to 9.19% and are being repaid over a 35-year period. Each of the lease-in lease-out arrangements allows for the natural gas distribution assets to be returned to the municipalities after a term of 17 years, being 2017 and 2022. The expected payments required if the assets are returned to the municipalities would equal the carrying values of the obligations on the consolidated balance sheet as at the respective payment dates.

The present value of the minimum lease payments required for the capital lease and finance obligations over the next five years and thereafter are as follows:

Year	Capital Leases *(in millions)*	Finance Obligations *(in millions)*	Total *(in millions)*
2014	$ 42	$ 4	$ 46
2015	42	4	46
2016	43	4	47
2017	44	4	48
2018	45	31	76
Thereafter	2,048	58	2,106
	$ 2,264	$ 105	$ 2,369
Less: Amounts representing imputed interest and executory costs on capital lease and finance obligations			(1,945)
Total capital lease and finance obligations			424
Less: Current portion			(7)
			$ 417

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17. Other Liabilities

(in millions)	**2013**	2012
OPEB plan liabilities *(Note 28)*	**$ 290**	$ 280
Defined benefit pension plan liabilities *(Note 28)*	**185**	264
Waneta Partnership promissory note *(Notes 33 and 35)*	**50**	47
MGP site remediation *(Notes 7 (vi) and 37)*	**42**	–
Deferred compensation plan liabilities *(Note 9)*	**16**	–
DSU and PSU liabilities *(Note 23)*	**10**	10
Unrecognized tax benefits *(Note 26)*	**3**	16
Other liabilities	**31**	21
	$ 627	$ 638

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2013, its discounted net present value was $50 million (December 31, 2012 – $47 million). The promissory note was incurred on the acquisition by the Waneta Partnership, from a company affiliated with CPC/CBT, of certain intangible assets and project design costs associated with the construction of the Waneta Expansion. The promissory note is payable on the fifth anniversary of the commercial operation date of the Waneta Expansion, which is projected to be in spring 2015.

Other liabilities primarily include customer deposits, AROs, deferred lease revenue and funds received in advance of expenditures.

18. Common Shares

Common shares issued during the year were as follows:

	2013		2012	
	Number of Shares *(in thousands)*	**Amount** *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	**191,566**	**$ 3,121**	188,828	$ 3,036
Public offering – Conversion of Subscription Receipts	**18,500**	**567**	–	–
Consumer Share Purchase Plan	**36**	**1**	44	1
Dividend Reinvestment Plan	**2,263**	**72**	1,848	60
Employee Share Purchase Plan	**369**	**12**	133	4
Stock Option Plans	**431**	**10**	713	20
Balance, end of year	**213,165**	**$ 3,783**	191,566	$ 3,121

In June 2012, to finance a portion of the acquisition of CH Energy Group, the Corporation sold 18.5 million Subscription Receipts at $32.50 each, for gross proceeds of approximately $601 million. On June 27, 2013, upon closing of the acquisition of CH Energy Group, each Subscription Receipt was exchanged, without payment of additional consideration, for one common share of Fortis. Each Subscription Receipt Holder also received a cash payment of $1.22 per Subscription Receipt, which is an amount equal to the aggregate amount of dividends declared per common share of Fortis for which record dates have occurred since the issuance of the Subscription Receipts. The proceeds to the Corporation upon conversion of the Subscription Receipts were approximately $567 million, net of after-tax expenses (Note 29).

The 2012 Employee Share Purchase Plan ("2012 ESPP") was approved at the May 4, 2012 Annual General Meeting of the Corporation's shareholders. Under the 2012 ESPP, common shares may be issued from treasury, acquired in the open market or a combination from treasury and the open market, as determined by the Corporation. The first shares issued from treasury under the 2012 ESPP occurred in September 2012.

19. Earnings Per Common Share

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 202.5 million for 2013 and 190.0 million for 2012.

Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

EPS were as follows:

	2013						
	Earnings to Common Shareholders from Continuing Operations *(in millions)*	**Extraordinary Gain** *(in millions)*	**Earnings to Common Shareholders** *(in millions)*	**Weighted Average Shares** *(in millions)*	**EPS from Continuing Operations**	**EPS from Extraordinary Gain**	**EPS**
Basic EPS	**$ 333**	**$ 20**	**$ 353**	**202.5**	**$ 1.64**	**$ 0.10**	**$ 1.74**
Effect of potential dilutive securities:							
Stock Options	**–**	**–**	**–**	**0.6**			
Preference Shares *(Note 20)*	**13**	**–**	**13**	**8.2**			
	346	**20**	**366**	**211.3**			
Deduct anti-dilutive impacts:							
Preference Shares	**(4)**	**–**	**(4)**	**(2.0)**			
Diluted EPS	**$ 342**	**$ 20**	**$ 362**	**209.3**	**$ 1.63**	**$ 0.10**	**$ 1.73**

	2012						
	Earnings to Common Shareholders from Continuing Operations *(in millions)*	Extraordinary Gain *(in millions)*	Earnings to Common Shareholders *(in millions)*	Weighted Average Shares *(in millions)*	EPS from Continuing Operations	EPS from Extraordinary Gain	EPS
Basic EPS	$ 315	$ –	$ 315	190.0	$ 1.66	$ –	$ 1.66
Effect of potential dilutive securities:							
Stock Options	–	–	–	0.8			
Preference Shares *(Note 20)*	17	–	17	10.3			
	332	–	332	201.1			
Deduct anti-dilutive impacts:							
Preference Shares	(7)	–	(7)	(3.9)			
Diluted EPS	$ 325	$ –	$ 325	197.2	$ 1.65	$ –	$ 1.65

20. Preference Shares

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value
(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		**2013**		2012	
First Preference Shares	Annual Dividend Per Share	**Number of Shares**	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Series C [(1)]	$ 1.3625	**–**	**$ –**	5,000,000	$ 123
Series E [(1)]	$ 1.2250	**7,993,500**	**197**	7,993,500	197
Series F [(1)]	$ 1.2250	**5,000,000**	**122**	5,000,000	122
Series G [(2)]	$ 0.9708	**9,200,000**	**225**	9,200,000	225
Series H [(2)]	$ 1.0625	**10,000,000**	**245**	10,000,000	245
Series J [(1)]	$ 1.1875	**8,000,000**	**196**	8,000,000	196
Series K [(2)]	$ 1.0000	**10,000,000**	**244**	–	–
		50,193,500	**$ 1,229**	45,193,500	$ 1,108

[(1)] Cumulative Redeemable First Preference Shares

[(2)] Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares. The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.

In July 2013 the Corporation redeemed all of the issued and outstanding $125 million 5.45% First Preference Shares, Series C at a redemption price of $25.1456 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share. Upon redemption, approximately $2 million of after-tax issuance costs associated with First Preference Shares, Series C were recognized in net earnings attributable to preference equity shareholders.

In July 2013 the Corporation issued 10 million Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series K ("First Preference Shares, Series K") at a price of $25.00 per share for net after-tax proceeds of $244 million.

Holders of the First Preference Shares, Series E, Series F and Series J are each entitled to receive a fixed cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal quarterly installments on the first day of each quarter.

On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradeable common shares of the Corporation, determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time. If a holder of First Preference Shares, Series E elects to convert any such shares into common shares, the Corporation can redeem such First Preference Shares, Series E for cash or arrange for the sale of those shares to other purchasers.

The Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series E into fully paid and freely tradeable common shares of the Corporation. The number of common shares into which each First Preference Share, Series E may be converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time.

The First Preference Shares, Series G, Series H and Series K are entitled to receive fixed cumulative cash dividends as and when declared by the Board of Directors of the Corporation in the amounts of $0.9708, $1.0625 and $1.0000 per share per annum, respectively, for each year up to but excluding September 1, 2018, June 1, 2015 and March 1, 2019, respectively. The dividends are payable in equal quarterly installments on the first day of each quarter. As at September 1, 2018, June 1, 2015, March 1, 2019 and each five-year period thereafter, the holders of First Preference Shares, Series G, Series H and Series K, respectively, are entitled to receive reset fixed cumulative cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preference Shares, Series G, Series H and Series K, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%, 1.45% and 2.05%, respectively.

On each First Preference Shares, Series H and Series K Conversion Date, the holders of First Preference Shares, Series H and Series K have the option to convert any or all of their First Preference Shares, Series H and Series K into an equal number of cumulative redeemable floating rate First Preference Shares, Series I and Series L, respectively. The holders of First Preference Shares, Series I and Series L will be entitled to receive floating rate cumulative cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate of the First Preference Shares, Series I and Series L will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45% and 2.05%, respectively.

On or after specified dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole at any time or in part from time to time, at specified fixed prices per share plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.

21. Accumulated Other Comprehensive Loss

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive loss by category is provided as follows.

		2013	
(in millions)	**Opening balance January 1**	**Net change**	**Ending balance December 31**
Net unrealized foreign currency translation losses:			
Unrealized foreign currency translation (losses) gains on net investments in foreign operations	**$ (115)**	**$ 55**	**$ (60)**
Gains (losses) on hedges of net investments in foreign operations	**45**	**(45)**	**–**
Income tax (expense) recovery	**(6)**	**6**	**–**
	(76)	**16**	**(60)**
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	**(3)**	**2**	**(1)**
Income tax recovery	**1**	**(1)**	**–**
	(2)	**1**	**(1)**
Unrealized employee future benefits (losses) gains: *(Note 28)*			
Unamortized past service costs	**(1)**	**(2)**	**(3)**
Unamortized net actuarial (losses) gains	**(19)**	**10**	**(9)**
Income tax recovery (expense)	**2**	**(1)**	**1**
	(18)	**7**	**(11)**
Accumulated other comprehensive loss	**$ (96)**	**$ 24**	**$ (72)**

		2012	
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Net unrealized foreign currency translation losses:			
Unrealized foreign currency translation losses on net investments in foreign operations	$ (103)	$ (12)	$ (115)
Gains on hedges of net investments in foreign operations	33	12	45
Income tax expense	(4)	(2)	(6)
	(74)	(2)	(76)
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	(4)	1	(3)
Income tax recovery	1	–	1
	(3)	1	(2)
Unrealized employee future benefits losses: *(Note 28)*			
Unamortized past service costs	(1)	–	(1)
Unamortized net actuarial losses	(19)	–	(19)
Income tax recovery	2	–	2
	(18)	–	(18)
Accumulated other comprehensive loss	$ (95)	$ (1)	$ (96)

22. Non-Controlling Interests

(in millions)	**2013**	2012
Waneta Partnership	**$ 280**	$ 220
Caribbean Utilities	**78**	71
Mount Hayes Limited Partnership	**11**	12
Preference shares of Newfoundland Power	**6**	7
	$ 375	$ 310

23. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2013, the Corporation had the following stock option plans: the 2012 Plan, the 2006 Plan and the 2002 Plan. The 2012 Plan was approved at the May 4, 2012 Annual General Meeting. The 2012 Plan will ultimately replace the 2002 and 2006 Plans. The 2002 and 2006 Plans will cease to exist when all outstanding options are exercised or expire in or before 2016 and 2018, respectively. The Corporation has ceased the granting of options under the 2002 and 2006 Plans and all new options granted after 2011 are being made under the 2012 Plan. Directors are not eligible to receive grants of options under the 2006 Plan or the 2012 Plan.

Options granted under the 2006 Plan are exercisable for a period not to exceed seven years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

Options granted under the 2012 Plan are exercisable for a period not to exceed ten years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

The following options were granted in 2013 and 2012.

	2013	2012
Options granted *(#)* (1)	**807,600**	789,220
Exercise price *($)* (2)	**33.58**	34.27
Grant date fair value *($)*	**3.91**	4.21

(1) Options were granted in March 2013 and May 2012
(2) Five-day volume weighted average trading price immediately preceding the date of grant

The fair values of the above option grants were estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

	2013	2012
Dividend yield *(%)* (1)	**3.78**	3.67
Expected volatility *(%)* (2)	**21.4**	22.2
Risk-free interest rate *(%)* (3)	**1.31**	1.50
Weighted average expected life *(years)* (4)	**5.3**	5.3

(1) Based on average annual dividend yield up to the date of grant and the weighted average expected life of the options
(2) Based on historical experience over a period equal to the weighted average expected life of the options
(3) Government of Canada benchmark bond yield in effect at the date of grant that covers the weighted average expected life of the options
(4) Based on historical experience

The Corporation records compensation expense upon the issuance of stock options granted under its 2002, 2006 and 2012 Plans. Using the fair value method, each grant is treated as a single award, the fair value of which is amortized to compensation expense evenly over the four-year vesting period of the options.

The following table summarizes information related to the stock options for 2013.

	Total Options		Non-vested Options [(1)]	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Grant Date Fair Value
Options outstanding, January 1, 2013	**4,742,665**	**$ 27.49**	**1,997,052**	**$ 4.34**
Granted	**807,600**	**$ 33.58**	**807,600**	**$ 3.91**
Exercised	**(430,527)**	**$ 19.46**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(814,610)**	**$ 4.32**
Options outstanding, December 31, 2013	**5,119,738**	**$ 29.13**	**1,990,042**	**$ 4.18**
Options vested, December 31, 2013 [(2)]	**3,129,696**	**$ 26.63**		

(1) As at December 31, 2013, there was $8 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of four years.
(2) As at December 31, 2013, the weighted average remaining term of vested options was three years with an aggregate intrinsic value of $12 million.

The following table summarizes additional 2013 and 2012 stock option information.

(in millions)	**2013**	2012
Stock option expense recognized	**$ 3**	$ 4
Stock options exercised:		
Cash received for exercise price	**8**	17
Intrinsic value realized by employees	**6**	7
Fair value of options that vested	**4**	4

Directors' DSU Plan

Under the Corporation's Directors' DSU Plan, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation. In addition, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of DSUs	**2013**	2012
DSUs outstanding, beginning of year	**175,326**	147,629
Granted	**32,883**	21,417
Granted – notional dividends reinvested	**7,520**	6,280
DSUs paid out	**(12,557)**	–
DSUs outstanding, end of year	**203,172**	175,326

For the year ended December 31, 2013, expense of less than $0.5 million (2012 – $1 million) was recognized in earnings with respect to the DSU Plan.

In 2013, 12,557 DSUs were paid out to a retired director at prices of $32.29 and $31.17 per DSU, for a total of approximately $0.5 million.

As at December 31, 2013, the liability related to outstanding DSUs has been recorded at the closing price of the Corporation's common shares of $30.45, for a total of $6 million (December 31, 2012 – $6 million), and is included in long-term other liabilities (Note 17).

For the years ended December 31, 2013 and 2012

23. Stock-Based Compensation Plans (cont'd)

PSU Plan

The Corporation's PSU Plan represents a component of the long-term incentives awarded to senior management of the Corporation and its subsidiaries, including the President and Chief Executive Officer ("CEO") of Fortis. In March 2013 the Corporation's Board of Directors approved the 2013 PSU Plan, effective January 1, 2013. Prior to 2013, the Corporation's PSU Plan was previously awarded only to the President and CEO of Fortis.

Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period, at which time a cash payment may be made, as determined by the Human Resources Committee of the Board of Directors. Each PSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of PSUs	**2013**	2012
PSUs outstanding, beginning of year	**178,012**	154,658
Granted	**136,058**	62,000
Granted – notional dividends reinvested	**10,327**	6,217
PSUs paid out	**(66,978)**	(44,863)
PSUs outstanding, end of year	**257,419**	178,012

In March 2013, 66,978 PSUs were paid out to the President and CEO of the Corporation at $33.59 per PSU, for a total of approximately $2 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2010 and the President and CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors.

In May 2013, 136,058 PSUs were granted to senior management of the Corporation and its subsidiaries. The maturation period of the May 2013 PSU grant is three years, at which time a cash payment may be made to senior management after evaluation by the Human Resources Committee of the Board of Directors of the achievement of payment requirements.

For the year ended December 31, 2013, expense of approximately $3 million (2012 – $2 million) was recognized in earnings with respect to the PSU Plan.

As at December 31, 2013, the liability related to outstanding PSUs has been recorded at the closing price of the Corporation's common shares of $30.45, for a total of $4 million (December 31, 2012 – $4 million), and is included in long-term other liabilities (Note 17).

24. Other Income (Expenses), Net

(in millions)	**2013**	2012
Equity component of AFUDC *(Note 3)*	**$ 8**	$ 7
Interest income	**7**	5
Net foreign exchange gain (loss) *(Note 9)*	**6**	(2)
Gain on sale of land	**1**	–
Other income, net of expenses	**–**	3
Acquisition-related expenses *(Notes 1 and 29)*	**(12)**	(9)
Acquisition-related customer and community benefits *(Notes 7 (xix) and 29)*	**(41)**	–
	$ (31)	$ 4

The foreign exchange gain (loss) is related to the translation into Canadian dollars of the Corporation's US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity (Notes 9, 34 and 36).

In 2013 Newfoundland Power recognized an approximate $1 million gain on the sale of vacant land.

The acquisition-related expenses and customer and community benefits are primarily associated with the acquisition of CH Energy Group, and also include expenses associated with the acquisition of UNS Energy.

25. Finance Charges

(in millions)	2013	2012
Interest – Long-term debt and capital lease and finance obligations	**$ 403**	$ 377
– Short-term borrowings	**9**	7
Debt component of AFUDC *(Note 3)*	**(23)**	(18)
	$ 389	$ 366

26. Income Taxes

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. Deferred income tax assets and liabilities are comprised of the following:

(in millions)	2013	2012
Deferred income tax liability (asset)		
Utility capital assets	**$ 1,082**	$ 684
Non-utility capital assets	**37**	30
Intangible assets	**37**	38
Regulatory assets	**182**	161
Other assets and liabilities (net)	**(105)**	(89)
Regulatory liabilities	**(170)**	(121)
Loss carryforwards	**(26)**	(17)
Unrealized foreign currency translation gains on long-term debt	**2**	8
Share issue and debt financing costs	**(2)**	2
Net deferred income tax liability	**$ 1,037**	$ 696
Current deferred income tax asset	**$ (42)**	$ (16)
Current deferred income tax liability	**8**	10
Long-term deferred income tax asset	**(7)**	–
Long-term deferred income tax liability	**1,078**	702
Net deferred income tax liability	**$ 1,037**	$ 696

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2013 and 2012.

(in millions)	2013	2012
Total unrecognized tax benefits, beginning of year	**$ 16**	$ 22
Additions related to the current year	**2**	1
Adjustments related to prior years	**(14)**	(3)
Reductions related to the lapse of applicable statutes of limitations	**(1)**	(4)
Total unrecognized tax benefits, end of year *(Note 17)*	**$ 3**	$ 16

In June 2013 the Government of Canada enacted changes associated with Part VI.1 tax on the Corporation's preference share dividends. In accordance with US GAAP, income taxes are required to be recognized based on enacted tax legislation. In 2013 the Corporation recognized a $23 million income tax recovery due to the enactment of higher deductions associated with Part VI.1 tax.

In 2013 a settlement was reached with Canada Revenue Agency resulting in the release of income tax provisions of approximately $5 million.

If the total amount of unrecognized tax benefits as at December 31, 2013 of $3 million (December 31, 2012 – $16 million) was ultimately realized, income tax expense for 2013 would not have changed (2012 – decreased by approximately $15 million). The Corporation has unrecognized tax benefits related to corporate transactions in a prior year that could increase earnings by approximately $3 million in 2014 if the transactions become statute-barred. The Corporation does not expect that the total unrecognized tax benefits will significantly change within the next 12 months.

Interest and penalties recognized as income tax expense related to liabilities for unrecognized tax benefits for 2013 were nil (2012 – $1 million). Interest and penalties accrued as accounts payable and accrued liabilities related to liabilities for unrecognized tax benefits as at December 31, 2013 were nil (December 31, 2012 – $8 million). Taxation years 2008 and prior are no longer subject to examination in Canada, other than transactions with related non-residents who are no longer subject to examination in Canada for taxation years 2005 and prior.

For the years ended December 31, 2013 and 2012

26. Income Taxes (cont'd)

The components of the provision for income taxes were as follows:

(in millions)	**2013**	2012
Canadian		
Current income taxes	**$ 41**	$ 46
Deferred income taxes	**78**	78
Less: regulatory adjustments	**(81)**	(61)
	(3)	17
Total Canadian	**$ 38**	$ 63
Foreign		
Current income taxes	**$ (3)**	$ (2)
Deferred income taxes	**(3)**	–
Total Foreign	**$ (6)**	$ (2)
Income tax expense	**$ 32**	$ 61

Income taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	**2013**	2012
Combined Canadian federal and provincial statutory income tax rate	**29.0%**	29.0%
Statutory income tax rate applied to earnings before income taxes	**$ 125**	$ 125
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(16)**	(13)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**(11)**	(13)
Items capitalized for accounting purposes but expensed for income tax purposes	**(54)**	(44)
Difference between capital cost allowance and amounts claimed for accounting purposes	**3**	1
Non-deductible expenses	**8**	4
Part VI.1 tax – difference between enacted and substantially enacted income tax rates and the effect of statute-barred reversals	**(23)**	4
Release of income tax reserves	**(7)**	(4)
Difference between employee future benefits paid and amounts expensed for accounting purposes	**1**	1
Other	**6**	–
Income tax expense	**$ 32**	$ 61
Effective tax rate	**7.4%**	14.1%

As at December 31, 2013, the Corporation had approximately $133 million (December 31, 2012 – $73 million) in non-capital and capital loss carryforwards, of which $12 million (December 31, 2012 – $13 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2033.

27. Extraordinary Gain, Net of Tax

Effective March 2013 the Corporation and the Government of Newfoundland and Labrador settled all matters, including release from all debt obligations, pertaining to the Government's December 2008 expropriation of non-regulated hydroelectric generating assets and water rights in central Newfoundland, then owned by Exploits Partnership, in which Fortis held an indirect 51% interest. As a result of the settlement an extraordinary gain of approximately $25 million ($20 million after tax) was recognized in 2013.

28. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans and defined contribution pension plans, including group RRSPs for employees. The Corporation, the FortisBC Energy companies, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario and Algoma Power also offer OPEB plans for qualifying employees.

For the defined benefit pension plan arrangements, the projected pension benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2010 and 2012 for the FortisBC Energy companies (plans covering non-unionized employees); as of December 31, 2010 for the FortisBC Energy companies (plan covering unionized employees); as of December 31, 2012 for FortisAlberta and FortisBC Electric; as of December 31, 2011 for the Corporation, Newfoundland Power and FortisOntario; as of July 1, 2012 for Algoma Power; and as of December 31, 2012 for Caribbean Utilities. The next required valuations for funding purposes will be, at the latest, three years from the date of the most recent actuarial valuation of each plan, as noted above. Central Hudson's funding requirements, however, are based on the *Pension Protection Act of 2006* and require contributions to be made to maintain the target fund percentage at 80% or higher. To ensure the target fund percentage is maintained at the required level, Central Hudson has an annual valuation performed.

The Corporation's investment policy is to ensure that the pension assets, together with expected contributions, are invested in a prudent and cost-effective manner so as to optimally meet the liabilities of the plans for its members. The investment objective of the pension plans is to maximize return in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and pension expense for financial statement purposes.

The Corporation's consolidated defined benefit pension and OPEB plan weighted average asset allocation were as follows:

Plan assets as at December 31 *(%)*	**2013 Target Allocation**	**2013**	2012
Equities	**51**	**52**	50
Fixed income	**46**	**43**	44
Real estate	**3**	**4**	6
Cash and other	**–**	**1**	–
	100	**100**	100

The fair value measurements of defined benefit pension and OPEB plan assets by fair value hierarchy, as defined in Note 33, were as follows:

Fair value of plan assets as at December 31, 2013

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Equities	**$ 289**	**$ 546**	**$ –**	**$ 835**
Fixed income	**46**	**701**	**–**	**747**
Real estate	**–**	**–**	**62**	**62**
Cash and other	**2**	**16**	**–**	**18**
	$ 337	**$ 1,263**	**$ 62**	**$ 1,662**

Fair value of plan assets as at December 31, 2012

(in millions)	Level 1	Level 2	Level 3	Total
Equities	$ 235	$ 195	$ –	$ 430
Fixed income	–	382	–	382
Real estate	–	–	53	53
Cash and other	2	1	–	3
	$ 237	$ 578	$ 53	$ 868

Notes to Consolidated Financial Statements

For the years ended December 31, 2013 and 2012

28. Employee Future Benefits (cont'd)

The following table is a reconciliation of changes in the fair value of pension plan assets that have been measured using Level 3 inputs for the years ended December 31, 2013 and 2012.

(in millions)	**2013**	2012
Balance, beginning of year	**$ 53**	$ 41
Actual return on plan assets held at end of year	**7**	5
Purchases, sales and settlements	**2**	7
Balance, end of year	**$ 62**	$ 53

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension plans and OPEB plans and their respective funded status.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2013**	2012	**2013**	2012
Change in benefit obligation [(1)]				
Balance, beginning of year	**$ 1,132**	$ 1,018	**$ 285**	$ 245
Liabilities assumed on acquisition	**638**	–	**169**	–
Service costs	**37**	27	**9**	6
Employee contributions	**14**	14	**–**	–
Interest costs	**59**	47	**15**	12
Benefits paid	**(60)**	(43)	**(9)**	(6)
Actuarial (gains) losses	**(99)**	69	**(55)**	27
Past services (credits) costs/plan amendments	**(4)**	–	**2**	1
Foreign currency translation impacts	**7**	–	**1**	–
Balance, end of year [(2)]	**$ 1,724**	$ 1,132	**$ 417**	$ 285
Change in value of plan assets				
Balance, beginning of year	**$ 868**	$ 785	**$ –**	$ –
Assets assumed on acquisition	**544**	–	**110**	–
Actual return on plan assets	**124**	67	**12**	–
Benefits paid	**(60)**	(43)	**(9)**	(6)
Employee contributions	**14**	14	**–**	–
Employer contributions	**44**	45	**7**	6
Foreign currency translation impacts	**7**	–	**1**	–
Balance, end of year	**$ 1,541**	$ 868	**$ 121**	$ –
Funded status	**$ (183)**	$ (264)	**$ (296)**	$ (285)

(1) Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans

(2) The accumulated benefit obligation for defined benefit pension plans, which includes no assumption about future salary levels, was $1,559 million as at December 31, 2013 (December 31, 2012 – $999 million).

Notes to Consolidated Financial Statements

The following table summarizes the employee future benefit assets and liabilities and their classifications on the consolidated balance sheet.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2013**	2012	**2013**	2012
Assets				
Defined benefit pension assets:				
Long-term other assets	**$ 3**	$ –	**$ –**	$ –
Liabilities				
Defined benefit pension liabilities:				
Current *(Note 14)*	**1**	–	**–**	–
Long-term other liabilities *(Note 17)*	**185**	264	**–**	–
OPEB plan liabilities:				
Current *(Note 14)*	**–**	–	**6**	5
Long-term other liabilities *(Note 17)*	**–**	–	**290**	280
Net liabilities	**$ 183**	$ 264	**$ 296**	$ 285

The net benefit cost for the Corporation's defined benefit pension plans and OPEB plans were as follows:

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2013**	2012	**2013**	2012
Components of net benefit cost				
Service costs	**$ 37**	$ 27	**$ 9**	$ 6
Interest costs	**59**	47	**15**	12
Expected return on plan assets	**(70)**	(50)	**(4)**	–
Amortization of actuarial losses	**39**	26	**8**	5
Amortization of past service costs (credits)/plan amendments	**1**	–	**(7)**	(3)
Amortization of transitional obligation	**–**	–	**–**	1
Regulatory adjustments	**(12)**	(10)	**2**	1
Net benefit cost	**$ 54**	$ 40	**$ 23**	$ 22

The following tables provide the components of accumulated other comprehensive loss and regulatory assets and liabilities, which would otherwise have been recognized as accumulated other comprehensive loss, for the years ended December 31, 2013 and 2012 that have not been recognized as components of net benefit cost.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2013**	2012	**2013**	2012
Unamortized net actuarial losses	**$ 8**	$ 15	**$ 1**	$ 4
Unamortized past service costs	**–**	–	**3**	1
Income tax recovery	**(1)**	(2)	**–**	–
Accumulated other comprehensive loss *(Note 21)*	**$ 7**	$ 13	**$ 4**	$ 5
Net actuarial losses	**$ 254**	$ 311	**$ 69**	$ 110
Past service credits	**1**	(1)	**(49)**	(23)
Transitional obligation	**–**	–	**–**	1
Amount deferred due to actions of regulators	**55**	40	**55**	60
	$ 310	$ 350	**$ 75**	$ 148
Regulatory assets *(Note 7 (ii))*	**$ 310**	$ 350	**$ 130**	$ 148
Regulatory liabilities *(Note 7 (ii))*	**–**	–	**(55)**	–
Net regulatory assets	**$ 310**	$ 350	**$ 75**	$ 148

28. Employee Future Benefits (cont'd)

The following tables provide the components recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2013**	2012	**2013**	2012
Current year net actuarial (gains) losses	**$ (5)**	$ 2	**$ (3)**	$ –
Past service costs/plan amendments	**–**	–	**2**	–
Amortization of actuarial losses	**(2)**	(2)	**–**	–
Income tax expense	**1**	–	**–**	–
Total recognized in comprehensive income	**$ (6)**	$ –	**$ (1)**	$ –
Current year net actuarial (gains) losses	**$ (150)**	$ 50	**$ (60)**	$ 27
Past service costs/plan amendments	**(4)**	–	**–**	–
Amortization of actuarial losses	**(36)**	(24)	**(7)**	(5)
Amortization of past service (costs) credits	**(1)**	–	**6**	4
Amortization of transitional obligation	**–**	–	**–**	(1)
Regulatory adjustments	**8**	3	**(2)**	1
Total recognized in regulatory assets	**$ (183)**	$ 29	**$ (63)**	$ 26

Net actuarial losses of $1 million are expected to be amortized from accumulated other comprehensive loss into net benefit cost in 2014 related to defined benefit pension plans.

Net actuarial losses of $28 million and regulatory adjustments of $1 million are expected to be amortized from regulatory assets into net benefit cost in 2014 related to defined benefit pension plans. Net actuarial losses of $4 million, past service credits of $3 million and regulatory adjustments of $6 million are expected to be amortized from regulatory assets into net benefit cost in 2014 related to OPEB plans.

Significant weighted average assumptions	Defined Benefit Pension Plans		OPEB Plans	
	2013	2012	**2013**	2012
Discount rate during the year *(%)*	**4.14**	4.62	**4.20**	4.65
Discount rate as at December 31 *(%)*	**4.76**	4.14	**4.73**	4.20
Expected long-term rate of return on plan assets *(%)* (1)	**6.29**	6.41	**7.33**	–
Rate of compensation increase *(%)*	**3.60**	3.39	**3.71**	3.71
Health care cost trend increase as at December 31 *(%)* (2)	**–**	–	**4.69**	4.62

(1) Developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

(2) The projected 2014 weighted average health care cost trend rate is 7.52% for OPEBs and is assumed to decrease over the next 12 years by 2025 to the weighted average ultimate health care cost trend rate of 4.69% and remain at that level thereafter.

For 2013 the effects of changing the health care cost trend rate by 1% were as follows:

(in millions)	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in accumulated benefit obligation	**$ 38**	**$ (31)**
Increase (decrease) in service and interest costs	**3**	**(2)**

The following table provides the amount of benefit payments expected to be made over the next 10 years.

Year	Defined Benefit Pension Payments *(in millions)*	OPEB Payments *(in millions)*
2014	$ 73	$ 16
2015	76	17
2016	79	18
2017	84	19
2018	89	21
2019 – 2023	501	115

Refer to Note 35 for expected defined benefit pension funding contributions.

During 2013 the Corporation expensed $16 million (2012 – $14 million) related to defined contribution pension plans.

29. Business Acquisitions

2013

CH ENERGY GROUP

On June 27, 2013, Fortis acquired all of the outstanding common shares of CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of US$518 million of debt on closing. The net cash purchase price of approximately $1,019 million (US$972 million) was primarily financed through proceeds from the issuance of 18.5 million common shares of Fortis, pursuant to the conversion of Subscription Receipts on the closing of the acquisition, for proceeds of approximately $567 million, net of after-tax expenses (Note 18), and a US$325 million unsecured notes offering by the Corporation (Note 15).

CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson, is a regulated transmission and distribution utility serving approximately 300,000 electric customers and 77,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson accounts for approximately 93% of the total assets of CH Energy Group and is subject to regulation by the PSC under a traditional COS model (Note 2). The determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change of ownership. Therefore, in determining the fair value of Central Hudson's assets and liabilities at the date of acquisition, fair value approximates book value. No fair value adjustments were recorded for the net assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to customers.

Non-regulated net assets acquired relate mainly to Griffith, which is primarily a fuel delivery business. Fair value approximates book value, with the exception of intangible assets associated with Griffith's customer relationships. In March 2014 CH Energy Group sold Griffith (Notes 8 and 38).

The following table summarizes the allocation of the purchase consideration to the assets and liabilities acquired as at June 27, 2013 based on their fair values, using an exchange rate of US$1.00=CDN$1.0484. The amount of the purchase price allocated to goodwill is entirely associated with the regulated gas and electric operations of Central Hudson.

29. Business Acquisitions (cont'd)

CH Energy Group (cont'd)

(in millions)	Total
Purchase consideration	**$ 1,019**
Fair value assigned to net assets:	
Current assets	**215**
Long-term regulatory assets	**235**
Utility capital assets	**1,283**
Non-utility capital assets	**11**
Intangible assets	**53**
Other long-term assets	**33**
Current liabilities	**(133)**
Assumed short-term borrowings	**(39)**
Assumed long-term debt (including current portion)	**(543)**
Long-term regulatory liabilities	**(123)**
Other long-term liabilities	**(468)**
	524
Cash and cash equivalents	**19**
Fair value of net assets acquired	**543**
Goodwill *(Note 13)*	**$ 476**

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on June 27, 2013.

Acquisition-related expenses totalled approximately $9 million ($6 million after tax) and have been recognized in other income (expenses), net on the consolidated statement of earnings (Note 24). In addition, approximately $41 million (US$40 million), or $26 million (US$26 million) after tax, in customer and community benefits offered to obtain regulatory approval of the acquisition were expensed as approved by the PSC, and were also recognized in other income (expenses), net on the consolidated statement of earnings (Notes 7 and 24).

Supplemental Pro Forma Data

The unaudited pro forma financial information below gives effect to the acquisition of CH Energy Group as if the transaction had occurred at the beginning of 2012. This pro forma data is presented for information purposes only, and does not necessarily represent the results that would have occurred had the acquisition taken place at the beginning of 2012, nor is it necessarily indicative of the results that may be expected in future periods.

(in millions)	**2013**	2012
Pro forma revenue [(1)]	**$ 4,400**	$ 4,298
Pro forma net earnings [(1)]	**473**	414

[(1)] Pro forma net earnings exclude all acquisition-related expenses incurred by CH Energy Group and the Corporation, net of tax (Note 24). A pro forma adjustment has been made to net earnings for the years presented to reflect the Corporation's after-tax financing costs associated with the acquisition. Pro forma revenue excludes amounts related to Griffith; however, pro forma net earnings for 2013 includes approximately $2.5 million related to Griffith (2012 – $3 million).

CITY OF KELOWNA'S ELECTRICAL UTILITY ASSETS

In March 2013 FortisBC Electric acquired the electrical utility assets of the City of Kelowna (the "City") for approximately $55 million, which allows FortisBC Electric to directly serve some 15,000 customers formerly served by the City. FortisBC Electric had provided the City with electricity under a wholesale tariff and had operated and maintained the City's electrical utility assets under contract since 2000.

The acquisition was approved by the BCUC in March 2013 and allowed for approximately $38 million of the purchase price to be included in FortisBC Electric's rate base. Based on this regulatory decision, the book value of the assets acquired has been assigned as fair value in the purchase price allocation. FortisBC Electric is regulated under COS and the determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change in ownership. Therefore, in determining the fair value of assets at the date of acquisition, fair value approximates book value. No fair value adjustments were recorded for the assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to customers.

The following table summarizes the allocation of the purchase price to the assets acquired as at the date of acquisition based on their fair values.

(in millions)		**Total**
Purchase consideration	**$**	**55**
Fair value assigned to assets:		
Utility capital assets		**38**
Long-term deferred income tax asset		**3**
Fair value of assets acquired		**41**
Goodwill *(Note 13)*	**$**	**14**

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing in March 2013.

2012

OTHER CANADIAN REGULATED ELECTRIC UTILITIES – PORT COLBORNE HYDRO ASSETS

In April 2012 FortisOntario exercised its option, under the terms of a 10-year operating lease agreement with the City of Port Colborne that commenced in April 2002, to purchase the remaining assets of Port Colborne Hydro for approximately $7 million. Under the lease arrangement with the City of Port Colborne, and now through ownership of the previously leased assets, FortisOntario operates and maintains the City of Port Colborne's electricity distribution system for provision of electricity service to the residents of Port Colborne. Throughout the 10-year lease term, FortisOntario incurred approximately $17 million in capital expenditures for Port Colborne Hydro's electricity distribution system. The exercise of the purchase option, which qualifies as a business combination, provides ownership and legal title to all of the assets, including equipment, real property and distribution assets, that constitute the entire electricity distribution system in Port Colborne. The purchase was approved by the OEB.

FortisOntario is regulated under COS and the determination of revenue and earnings is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, fair value approximates book value and no adjustments were recorded for the assets acquired, because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to customers. Accordingly, $3 million of the purchase price was allocated to utility capital assets and $4 million was recognized as goodwill in the purchase price allocation (Note 13). The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing in April 2012.

REGULATED ELECTRIC UTILITIES CARIBBEAN – TCU

In August 2012 FortisTCI acquired TCU for an aggregate cash purchase price of approximately $13 million (US$13 million), including the assumption of $5 million (US$5 million) of debt on closing. TCU is a regulated electric utility operating pursuant to a 50-year licence expiring in 2036. The utility serves more than 2,000 residential and commercial customers on Grand Turk and Salt Cay with a diesel-powered generating capacity of 9 MW. TCU is regulated under COS and the determination of revenue and earnings is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, fair value approximates book value and no adjustments were recorded for the net assets acquired, because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to customers. Accordingly, approximately $9 million of the purchase price was allocated to utility capital assets, $3 million to net current assets, $5 million to long-term debt and $1 million was recognized as goodwill in the purchase price allocation (Note 13). The acquisition has been accounted for using the acquisition method, whereby financial results of TCU have been consolidated in the financial statements of Fortis commencing in August 2012.

NON-REGULATED – STATIONPARK ALL SUITE HOTEL

In October 2012 Fortis Properties acquired the StationPark All Suite Hotel for an aggregate cash purchase price of $13 million, including the assumption of $6 million of debt on closing. Accordingly, $13 million of the purchase price was allocated to non-utility capital assets and $6 million was allocated to long-term debt. The acquisition has been accounted for using the acquisition method, whereby financial results of the hotel have been consolidated in the financial statements of Fortis commencing in October 2012.

30. Segmented Information

Information by reportable segment is as follows:

	REGULATED UTILITIES								NON-REGULATED				
	Gas	Gas & Electric	Electric Utilities										
Year Ended December 31, 2013 *($ millions)*	FortisBC Energy Companies – Canadian	Central Hudson – US	Fortis Alberta	FortisBC Electric	NF Power	Other Canadian	Total Electric Canadian	Electric Caribbean	Fortis Generation	Non-Utility	Corporate and Other	Inter-segment eliminations	Total
Revenue	1,378	335	475	317	601	374	1,767	290	35	248	26	(32)	4,047
Energy supply costs	600	116	–	84	390	248	722	179	1	–	–	(1)	1,617
Operating expenses	295	148	161	84	81	50	376	33	10	170	13	(8)	1,037
Depreciation and amortization	180	21	150	49	52	25	276	35	5	22	2	–	541
Operating income	303	50	164	100	78	51	393	43	19	56	11	(23)	852
Other income (expenses), net	3	2	4	1	4	–	9	2	1	(1)	(45)	(2)	(31)
Finance charges	142	16	73	39	36	20	168	13	1	26	48	(25)	389
Income tax expense (recovery)	36	13	1	12	(3)	5	15	–	–	11	(43)	–	32
Net earnings (loss) from continuing operations	128	23	94	50	49	26	219	32	19	18	(39)	–	400
Earnings from discontinued operations, net of tax	–	–	–	–	–	–	–	–	–	–	–	–	–
Extraordinary gain, net of tax	–	–	–	–	–	–	–	–	20	–	–	–	20
Net earnings (loss)	128	23	94	50	49	26	219	32	39	18	(39)	–	420
Non-controlling interests	1	–	–	–	–	–	–	9	–	–	–	–	10
Preference share dividends	–	–	–	–	–	–	–	–	–	–	57	–	57
Net earnings (loss) attributable to common equity shareholders	127	23	94	50	49	26	219	23	39	18	(96)	–	353
Goodwill	913	483	227	235	–	67	529	150	–	–	–	–	2,075
Identifiable assets	4,618	1,770	3,061	1,764	1,400	699	6,924	694	873	801	636	(483)	15,833
Total assets	5,531	2,253	3,288	1,999	1,400	766	7,453	844	873	801	636	(483)	17,908
Gross capital expenditures	215	57	429	69	92	56	646	52	146	46	13	–	1,175
Year Ended December 31, 2012 *($ millions)*													
Revenue	1,426	–	448	306	581	353	1,688	273	31	242	24	(30)	3,654
Energy supply costs	669	–	–	76	380	227	683	170	1	–	–	(1)	1,522
Operating expenses	287	–	158	85	74	48	365	34	9	166	14	(7)	868
Depreciation and amortization	160	–	133	48	44	26	251	32	4	21	2	–	470
Operating income	310	–	157	97	83	52	389	37	17	55	8	(22)	794
Other income (expenses), net	2	–	4	1	2	–	7	2	3	–	(9)	(1)	4
Finance charges	142	–	65	39	36	21	161	13	2	24	47	(23)	366
Income tax expense (recovery)	31	–	–	9	11	7	27	–	1	9	(7)	–	61
Net earnings (loss)	139	–	96	50	38	24	208	26	17	22	(41)	–	371
Non-controlling interests	1	–	–	–	1	–	1	7	–	–	–	–	9
Preference share dividends	–	–	–	–	–	–	–	–	–	–	47	–	47
Net earnings (loss) attributable to common equity shareholders	138	–	96	50	37	24	207	19	17	22	(88)	–	315
Goodwill	913	–	227	221	–	67	515	140	–	–	–	–	1,568
Identifiable assets	4,595	–	2,776	1,705	1,389	720	6,590	636	737	655	615	(446)	13,382
Total assets	5,508	–	3,003	1,926	1,389	787	7,105	776	737	655	615	(446)	14,950
Gross capital expenditures	222	–	442	69	86	48	645	48	196	35	–	–	1,146

Related party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions during the years ended December 31 were as follows:

Significant Related Party Inter-Segment Transactions

(in millions)	**2013**	2012
Sales from Newfoundland Power to Non-Utility	**$ 5**	$ 5
Sales from Fortis Generation to Other Canadian Electric Utilities	**1**	1
Inter-segment finance charges on lending from:		
Fortis Generation to Other Canadian Electric Utilities	**1**	2
Corporate to Regulated Electric Utilities – Caribbean	**4**	4
Corporate to Fortis Generation	**–**	1
Corporate to Non-Utility	**18**	16

The significant related party inter-segment asset balances as at December 31 were as follows:

(in millions)	**2013**	2012
Inter-segment borrowings from:		
Fortis Generation to Other Canadian Electric Utilities	**$ 20**	$ 20
Corporate to Regulated Electric Utilities – Caribbean	**85**	85
Corporate to Fortis Generation	**–**	9
Corporate to Non-Utility	**366**	307
Other inter-segment assets	**12**	25
Total inter-segment eliminations	**$ 483**	$ 446

31. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	**2013**	2012
Cash paid for:		
Interest	**$ 411**	$ 374
Income taxes	**57**	83
Change in non-cash operating working capital:		
Accounts receivable	**$ (44)**	$ 49
Prepaid expenses	**(13)**	1
Regulatory assets – current portion	**73**	(32)
Inventories	**7**	3
Accounts payable and other current liabilities	**(96)**	36
Regulatory liabilities – current portion	**28**	21
	$ (45)	$ 78
Non-cash investing and financing activities:		
Common share dividends reinvested	**$ 70**	$ 58
Additions to utility capital assets, non-utility capital assets and intangible assets included in current liabilities	**107**	88
Contributions in aid of construction included in current assets	**16**	17
Exercise of stock options into common shares	**1**	3

32. Derivative Instruments and Hedging Activities

The Corporation generally limits the use of derivative instruments to those that qualify as accounting or economic hedges. As at December 31, 2013, the Corporation's derivative instruments primarily consisted of electricity swap contracts, gas swap and option contracts, and gas purchase contract premiums. Electricity swap contracts are held by Central Hudson. Gas swap and option contracts, and gas purchase contract premiums are held by the FortisBC Energy companies and Central Hudson.

Volume of Derivative Activity

As at December 31, 2013, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

	2014	2015	2016	2017
Electricity swap contracts *(gigawatt hours)*	1,340	1,095	659	219
Gas swap and option contracts *(petajoules)*	6	–	–	–
Gas purchase contract premiums *(petajoules)*	77	14	–	–

Presentation of Derivative Instruments in the Consolidated Financial Statements

On the Corporation's consolidated balance sheet, derivative instruments are presented on a net basis by counterparty, where the right of offset exists.

The Corporation's outstanding derivative balances as at December 31 were as follows:

(in millions)	**2013**	2012
Gross derivative asset [(1)]	**$ 10**	$ –
Gross derivative liability [(1)]	**(15)**	(60)
	(5)	(60)
Netting [(2)]	**–**	–
Cash collateral	**–**	–
Total derivative balance [(3)]	**$ (5)**	$ (60)

[(1)] Refer to Note 33 for a discussion of the valuation techniques used to calculate the fair value of the derivative instruments.
[(2)] Positions, by counterparty, are netted where the intent and legal right to offset exists.
[(3)] Unrealized losses of $15 million on commodity risk-related derivative instruments were recognized in current regulatory assets as at December 31, 2013 (December 31, 2012 – $60 million) and unrealized gains of $10 million were recognized in current and long-term regulatory liabilities. These unrealized losses and gains would otherwise be recognized in earnings.

Cash flows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's consolidated statements of cash flows.

33. Fair Value Measurements

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value. The Corporation is required to record all derivative instruments at fair value except for those that qualify for the normal purchase and normal sale exception.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets;
Level 2: Fair value determined using pricing inputs that are observable; and
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

The following table details the estimated fair value measurements of the Corporation's financial instruments, all of which were measured using Level 2 pricing inputs, except for other investments and certain long-term debt and derivative instruments as noted.

Asset (Liability)	**2013**		2012	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term other asset – Belize Electricity [(1)]	**$ 108**	**$ n/a [(2)]**	$ 104	$ n/a [(2)]
Other investments [(1)] [(3)]	**6**	**6**	–	–
Long-term debt, including current portion *(Note 15)* [(4)]	**(7,204)**	**(8,084)**	(5,900)	(7,338)
Waneta Partnership promissory note [(5)]	**(50)**	**(50)**	(47)	(51)
Fuel option contracts	**–**	**–**	(1)	(1)
Electricity swap contracts [(6)]	**10**	**10**	–	–
Natural gas derivatives: [(7)]				
Gas swap and option contracts	**(13)**	**(13)**	(51)	(51)
Gas purchase contract premiums	**(2)**	**(2)**	(8)	(8)

[(1)] Included in long-term other assets on the consolidated balance sheet (Note 9)

[(2)] The Corporation's expropriated investment in Belize Electricity is recognized at book value, including foreign exchange impacts, in long-term other assets on the consolidated balance sheet. The actual amount of compensation that the GOB may pay to Fortis is indeterminable at this time (Notes 34 and 36).

[(3)] Other investments were valued using Level 1 inputs.

[(4)] The Corporation's $200 million unsecured debentures due 2039 and consolidated borrowings under credit facilities classified as long-term debt of $313 million (December 31, 2012 – $150 million) are valued using Level 1 inputs. All other long-term debt was valued using Level 2 inputs.

[(5)] Included in long-term other liabilities on the consolidated balance sheet (Note 17)

[(6)] The fair value of the electricity swap contracts is recorded in accounts receivable and other long-term assets (Notes 5 and 9). The fair value of electricity swap contracts was determined using Level 3 inputs.

[(7)] The fair value of the natural gas derivatives is recorded in accounts payable and other current liabilities as at December 31, 2013 and 2012 (Note 14).

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The electricity swap contracts and natural gas derivatives are used by Central Hudson to minimize commodity price volatility for electricity and natural gas purchases for the Company's full-service customers by fixing the effective purchase price for the defined commodities. The fair values of the electricity swap contracts and natural gas derivatives were calculated using forward pricing provided by independent third parties.

The natural gas derivatives are used by the FortisBC Energy companies to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The fair values of the electricity swap contracts and natural gas derivatives are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates. As at December 31, 2013, none of the electricity swap contracts and natural gas derivatives were designated as hedges of electricity and natural gas supply contracts. However, any gains or losses associated with changes in the fair value of the derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators.

34. Financial Risk Management

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash equivalents, trade and other accounts receivable, and long-term other receivables, the Corporation's credit risk is generally limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at December 31, 2013, FortisAlberta's gross credit risk exposure was approximately $106 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to $1 million by obtaining from the retailers either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The FortisBC Energy companies and Central Hudson may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The companies use netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist. The following table summarizes the FortisBC Energy companies' net credit risk exposure to its counterparties, as well as credit risk exposure to counterparties accounting for greater than 10% net credit exposure, as it relates to its natural gas swaps and options, as at December 31, 2013 and 2012.

(in millions, except as noted)	**2013**	2012
Gross credit exposure before credit collateral [(1)]	**$ 13**	$ 51
Credit collateral	**–**	–
Net credit exposure [(2)]	**$ 13**	$ 51
Number of counterparties > 10% (#)	**2**	4
Net exposure to counterparties > 10%	**$ 11**	$ 45

[(1)] Gross credit exposure equals mark-to-market value on physically and financially settled contracts, notes receivable and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported do not include adjustments for time value or liquidity.
[(2)] Net credit exposure is the gross credit exposure collateral minus credit collateral (cash deposits and letters of credit).

The Corporation is exposed to credit risk associated with the amount and timing of fair value compensation that Fortis is entitled to receive from the GOB as a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB on June 20, 2011. As at December 31, 2013, the Corporation had a long-term other asset of $108 million (December 31, 2012 – $104 million), including foreign exchange impacts, recognized on the consolidated balance sheet related to its expropriated investment in Belize Electricity (Notes 9, 33 and 36).

Additionally, as at December 31, 2013, Belize Electricity owed BECOL approximately US$4 million for energy purchases, of which less than US$1 million was overdue (December 31, 2012 – US$8 million, of which US$7 million was overdue). In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's committed corporate credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. Over the next five years, average annual consolidated long-term debt maturities and repayments are expected to be approximately $335 million. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at December 31, 2013, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.7 billion, of which approximately $2.2 billion was unused, including $785 million unused under the Corporation's $1 billion committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.6 billion of the total credit facilities are committed facilities with maturities ranging from 2014 through 2018.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

(in millions)	Regulated Utilities	Non-Regulated	Corporate and Other	**Total as at December 31, 2013**	Total as at December 31, 2012
Total credit facilities	$ 1,546	$ 119	$ 1,030	**$ 2,695**	$ 2,460
Credit facilities utilized:					
Short-term borrowings [(1)]	(157)	(3)	–	**(160)**	(136)
Long-term debt *(Note 15)* [(2)]	(99)	–	(214)	**(313)**	(150)
Letters of credit outstanding	(65)	–	(1)	**(66)**	(67)
Credit facilities unused	$ 1,225	$ 116	$ 815	**$ 2,156**	$ 2,107

(1) The weighted average interest rate on short-term borrowings was approximately 1.3% as at December 31, 2013 (December 31, 2012 – 1.9%)

(2) As at December 31, 2013, credit facility borrowings classified as long term included $43 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2012 – $62 million). The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 1.8% as at December 31, 2013 (December 31, 2012 – 2.1%).

As at December 31, 2013 and 2012, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

FEI has a $500 million unsecured committed revolving credit facility, maturing in August 2015. FEVI has a $200 million unsecured committed revolving credit facility, maturing in December 2015. The facilities are utilized to finance working capital requirements and capital expenditures and for general corporate purposes.

Central Hudson has a US$150 million ($159 million) unsecured committed revolving credit facility, maturing in October 2016, that is utilized to finance capital expenditures and for general corporate purposes.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2018, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, of which $50 million matures in May 2014 and the remaining $100 million matures in May 2016. Additionally, the Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has $120 million of unsecured credit facilities, comprised of a $100 million committed revolving credit facility, which matures in August 2017, and a $20 million demand credit facility.

Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2014, and a $5 million unsecured demand credit facility.

FortisOntario has a $30 million unsecured revolving credit facility, maturing in June 2014.

Caribbean Utilities has unsecured credit facilities totalling approximately US$47 million ($50 million).

Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$21 million ($22 million), maturing in June 2014.

34. Financial Risk Management (cont'd)

Liquidity Risk (cont'd)

Non-Regulated – Non-Utility

Fortis Properties has a $13 million secured revolving demand credit facility that can be utilized for general corporate purposes.

CH Energy Group has a US$100 million ($106 million) unsecured revolving credit facility, maturing in October 2015, that can be utilized for general corporate purposes.

Corporate and Other

Fortis has a $1 billion unsecured committed revolving credit facility, maturing in July 2018, that is available for general corporate purposes and interim financing of acquisitions. In January 2014, as a result of closing the $1.8 billion convertible debentures related to the pending acquisition of UNS Energy, Fortis agreed to maintain availability under its committed revolving corporate credit facility of not less than $600 million to cover the principal amount of the first installment of the convertible debentures in the event of a mandatory redemption (Note 38).

FHI has a $30 million unsecured committed revolving credit facility, maturing in May 2014, that is available for general corporate purposes.

For the purpose of financing the pending acquisition of UNS Energy (Note 1), in December 2013 the Corporation obtained a commitment letter from a syndicate of banks led by The Bank of Nova Scotia to provide an aggregate of $2 billion non-revolving term credit facilities, consisting of a $1.7 billion short-term bridge facility, repayable in full nine months following its advance, and a $300 million medium-term bridge facility, repayable in full on the second anniversary of its advance. The credit facilities table on the previous page does not include these $2 billion credit facilities.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2013, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A– / Negative (long-term corporate and unsecured debt credit rating)
DBRS	A(low) / Under Review – Developing Implications (unsecured debt credit rating)

The above-noted credit ratings reflect the Corporation's business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining low levels of debt at the holding company level. In December 2013, after the announcement by Fortis that it had entered into an agreement to acquire UNS Energy, DBRS placed the Corporation's credit rating under review with developing implications. Similarly, S&P revised its outlook on the Corporation to negative from stable. S&P indicated that an outlook revision to stable would likely occur when the Corporation's $1.8 billion convertible debentures, issued in January 2014, are converted to equity (Note 38).

Market Risk

Foreign Exchange Risk

The Corporation's earnings from, and net investment in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Central Hudson, Caribbean Utilities, Fortis Turks and Caicos, BECOL, FortisUS Energy and Griffith is the US dollar.

As at December 31, 2013, the Corporation's corporately issued US$1,033 million (December 31, 2012 – US$557 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at December 31, 2013, the Corporation had approximately US$560 million (December 31, 2012 – US$17 million) in foreign net investments remaining to be hedged. Both the Corporation's US dollar-denominated long-term debt and foreign net investments as at December 31, 2013 were significantly impacted by the CH Energy Group acquisition. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity (Notes 9, 33 and 36) does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity are recognized in earnings. In 2013 the Corporation recognized in earnings a foreign exchange gain of approximately $6 million (2012 – a foreign exchange loss of approximately $2 million) (Note 24).

Interest Rate Risk

The Corporation and most of its subsidiaries are exposed to interest rate risk associated with borrowings under variable-rate credit facilities and the refinancing of long-term debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk.

Commodity Price Risk

The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas and Central Hudson is exposed to commodity price risk associated with changes in the market price of electricity and natural gas (Notes 32 and 33). The risks have been reduced by entering derivative contracts that effectively fix the price of natural gas purchases and electricity purchases, respectively. The natural gas and electricity derivatives are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, as permitted by the regulators, for recovery from, or refund to, customers in future rates.

The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, mitigate gas price volatility on customer rates and reduce the risk of regional price discrepancies. As directed by the regulator, the FortisBC Energy companies have suspended their commodity hedging activities, with the exception of certain limited swaps as permitted by the regulator. The existing hedging contracts will continue in effect through to their maturities and the FortisBC Energy companies' ability to fully recover the cost of gas in customer rates remains unchanged. Any differences between the cost of natural gas purchased and the price of natural gas included in customer rates are recorded as regulatory deferrals and are recovered from, or refunded to, customers in future rates, subject to regulatory approval.

35. Commitments

As at December 31, 2013, the Corporation's consolidated commitments in each of the next five years and for periods thereafter, excluding repayments of long-term debt and capital lease and finance obligations separately disclosed in Notes 15 and 16, respectively, are as follows:

(in millions)	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Interest obligations on long-term debt	**$ 7,298**	$ 402	$ 363	$ 348	$ 322	$ 317	$ 5,546
Government loan obligations (1)	**15**	–	10	5	–	–	–
Gas purchase contract obligations (2)	**444**	312	66	18	16	11	21
Power purchase obligations							
Central Hudson (3)	**40**	10	6	6	6	3	9
FortisBC Electric (4)	**30**	13	9	5	3	–	–
FortisOntario (5)	**309**	48	50	51	52	53	55
Maritime Electric (6)	**102**	40	40	8	1	1	12
Capital cost (7)	**542**	21	19	21	19	21	441
Operating lease obligations (8)	**30**	6	5	5	5	5	4
Waneta Partnership promissory note (9)	**72**	–	–	–	–	–	72
Joint-use asset and shared service agreements (10)	**53**	3	3	3	3	2	39
Defined benefit pension funding contributions (11)	**77**	42	20	12	–	–	3
PSU Plan obligations (12)	**8**	2	2	4	–	–	–
Other (13)	**7**	3	–	–	–	–	4
Total	**$ 9,027**	$ 902	$ 593	$ 486	$ 427	$ 413	$ 6,206

(1) In prior years, FEVI received non-interest bearing repayable loans from the Government of Canada and the Government of British Columbia of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. As the loans are repaid and replaced with non-government debt financing, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure. At December 31, 2013, $10 million of the government loan payable is included in the current portion of long-term debt.

(2) Gas purchase contract obligations include various gas purchase contracts at the FortisBC Energy companies and Central Hudson. At the FortisBC Energy companies the obligations include the gross cash payments associated with natural gas derivatives (Note 32) and are based on market prices that vary with gas indices and reflect index prices that were in effect as at December 31, 2013. At Central Hudson the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2013.

35. Commitments (cont'd)

(3) Central Hudson must acquire sufficient peak load capacity to meet the peak load requirements of its full-service customers. This capacity requirement is met through contracts with capacity providers, purchases from the New York Independent System Operator ("NYISO") capacity market and the Company's own generating capacity.

In November 2013 Central Hudson entered into a contract to purchase 200 MW of installed capacity from May 1, 2014 through April 30, 2017. The NYISO has been authorized by FERC to create a new capacity zone in the Lower Hudson Valley, to maintain system reliability and attract investments in new and existing generation, which is expected to be implemented in May 2014. The key terms of the contract provide that Central Hudson will pay the settlement price in the NYISO Capacity Spot Market auction for the relevant month of delivery minus US$0.175 per kilowatt-month, times the contract quantity of the product delivered during the month. Due to uncertainties associated with finalization of the new capacity zone and future capacity prices by the NYISO, the amounts associated with this contract cannot be reasonably determined and estimated at this time and are not included in the Commitments table.

(4) Power purchase obligations for FortisBC Electric are comprised of a PPA with BC Hydro, a capacity agreement with Powerex Corp. ("Powerex"), and a capacity and energy purchase agreement with Brilliant Expansion Power Corporation ("Brilliant Corporation").

In May 2013 FortisBC Electric entered into a new PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 gigawatt hours ("GWh") of associated energy annually for a 20-year term beginning October 1, 2013. This new PPA does not change the basic parameters of the BC Hydro PPA that expired on September 30, 2013. An executed version of the PPA was submitted by BC Hydro to the BCUC in May 2013 and is pending regulatory approval. In the interim period until the new PPA is approved by the BCUC, FortisBC Electric and BC Hydro have agreed to continue under the terms of the expired BC Hydro PPA. Power purchases in the interim are approved for recovery in customer rates. The power purchases from the new PPA are expected to be recovered in customer rates. The amounts associated with the new PPA have not been included in the Commitments table above, pending review and approval by the BCUC.

In 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity through to February 2016 from Powerex, a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC Electric brings any new resources, such as capital or contractual projects, online prior to the expiry of the agreement, FortisBC Electric may terminate the contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex. The capacity being purchased under the agreement does not relate to a specific plant.

In November 2012 FortisBC Electric entered into an agreement to purchase capacity and energy from January 2013 through December 2017 from CPC acting on behalf of Brilliant Corporation. The capacity and energy being purchased under this agreement do not constitute a significant portion of the output of a specific plant. The agreement was accepted by the BCUC in December 2012.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"). The WECA allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. In May 2012 the WECA was accepted for filing as an energy supply contract by the BCUC. Amounts associated with the WECA have not been included in the Commitments table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

In 2013 FortisBC Electric entered into various agreements to purchase fixed-price winter capacity and energy purchases through 2015. The purchases under these agreements do not relate to specific plants.

(5) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of energy and capacity. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(6) Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In 2010 the Company signed a five-year take-or-pay contract with New Brunswick Power covering the period March 1, 2011 through February 29, 2016. The contract includes fixed pricing for the entire five-year period. The other take-or-pay contract, which is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States, expires in November 2032.

(7) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit. A major refurbishment of Point Lepreau that began in 2008 was completed and the facility returned to service in November 2012. The refurbishment is expected to extend the facility's estimated life for an additional 27 years.

(8) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases.

(9) Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion. The amount disclosed is on a gross cash flow basis. The promissory note was recorded in long-term other liabilities at its discounted net present value of $50 million as at December 31, 2013 (Note 17).

(10) FortisAlberta and an Alberta transmission service provider have entered into an agreement to allow for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission system. Due to the unlimited term of this agreement, the calculation of future payments after 2018 includes payments to the end of 20 years. However, payments under this agreement may continue for an indefinite period of time.

FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. In the fourth quarter of 2013, FortisAlberta withdrew its notice to terminate these agreements and reinstated the minimum expiry terms of five years from September 1, 2010, subject to extension based on mutually agreeable terms.

(11) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2013 and 2015 – FortisBC Energy companies (plans covering non-unionized employees)
December 31, 2013 – FortisBC Energy companies (plan covering unionized employees)
December 31, 2013 – FortisBC Electric
December 31, 2014 – Newfoundland Power

As a result of the December 2011 actuarial valuation completed at Newfoundland Power in April 2012, the Company is required to fund a solvency deficiency of approximately $53 million, including interest, over five years which began in 2012 and is reflected in the Commitments table. The defined benefit pension funding contributions, including current service and solvency deficit funding amounts, are expected to be $14 million in 2014. The increase in funding contributions is expected to be recovered from customers in future rates.

(12) The settlement of PSUs outstanding as at December 31, 2013, which were granted in each of 2011, 2012 and 2013, is subject to the satisfaction of payment criteria over the three-year vesting periods by senior management of the Corporation and its subsidiaries, including the President and CEO of Fortis (Note 23).

The Corporation's $6 million liability related to outstanding DSUs as at December 31, 2013 (Note 23) has been excluded from the Commitments table, as the timing of the payments is indeterminable at this time.

(13) Other contractual obligations mainly include building operating leases and AROs.

Other Commitments

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $1.4 billion for 2014. Over the five years 2014 through 2018, the Corporation's consolidated capital expenditure program, excluding capital spending at UNS Energy, is expected to exceed $6.5 billion, which has not been included in the Commitments table.

Pending Acquisition: In December 2013 Fortis entered into an agreement and plan of merger to acquire UNS Energy for US$60.25 per common share in cash, representing an aggregate purchase price of approximately US$4.3 billion, including the assumption of approximately US$1.8 billion of debt on closing (Note 1). The agreement and plan of merger may be terminated by the Corporation or UNS Energy at any time prior to closing in certain circumstances, including if the acquisition has not closed by December 11, 2014, provided, however, that if the only unsatisfied conditions to closing are the obtaining of the regulatory approvals as defined in the agreement and plan of merger, then such date shall be extended to June 11, 2015.

Convertible Debentures Represented by Installment Receipts: To finance a portion of the pending acquisition of UNS Energy, in January 2014 Fortis, through a direct wholly owned subsidiary, completed the sale of $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures of the Corporation represented by Installment Receipts (the "Debentures") (Note 38).

Other: In 2012 Caribbean Utilities entered into primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2014 is 18.9 million imperial gallons. The contracts expire in July 2014 with the option to renew for two additional 18-month terms. The renewal options can be exercised only within six months of the expiry dates of the existing contracts.

35. Commitments (cont'd)

Other Commitments (cont'd)

FortisTCI has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $902 million as at December 31, 2013 have been excluded from the Commitments table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination, or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 7.

The FortisBC Energy companies have issued commitments to customers to provide Energy Efficiency and Conservation and Natural Gas Vehicle funding under the respective programs approved by the BCUC. As at December 31, 2013, approximately $24 million of funding had been committed to customers.

36. Expropriated Assets

On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. Consequent to the deprivation of control over the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, as of June 20, 2011, and classified the book value, including foreign exchange impacts, of the expropriated investment as a long-term other asset on the consolidated balance sheet.

In October 2011 Fortis commenced an action in the Belize Supreme Court with respect to challenging the constitutionality of the expropriation of the Corporation's investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment and submitted its claim for compensation to the GOB in November 2011. The book value of the long-term other asset is below fair value as at the date of expropriation as determined by independent valuators. The GOB also commissioned a valuation of Belize Electricity, which is significantly lower than both the fair value determined under the Corporation's valuation and the book value of the long-term other asset.

In July 2012 the Belize Supreme Court dismissed the Corporation's claim of October 2011. Also in July 2012, Fortis filed its appeal of the above-noted trial judgment in the Belize Court of Appeal. The appeal was heard in October 2012 and a decision is pending. Any decision of the Belize Court of Appeal may be appealed to the Caribbean Court of Justice, the highest court of appeal available for judicial matters in Belize.

Fortis believes it has a strong, well-positioned case before the Belize Courts supporting the unconstitutionality of the expropriation. There exists, however, a possibility that the outcome of the litigation may be unfavourable to the Corporation and the amount of compensation otherwise to be paid to Fortis under the legislation expropriating Belize Electricity could be lower than the book value of the Corporation's expropriated investment in Belize Electricity. The book value was $108 million, including foreign exchange impacts, as at December 31, 2013 (December 31, 2012 – $104 million). If the expropriation is held to be unconstitutional, it is not determinable at this time as to the nature of the relief that would be awarded to Fortis; for example: (i) ordering return of the shares to Fortis and/or award of damages; or (ii) ordering compensation to be paid to Fortis for the unconstitutional expropriation of the shares and/or award of damages. Based on presently available information, the $108 million long-term other asset is not deemed impaired as at December 31, 2013. Fortis will continue to assess for impairment each reporting period based on evaluating the outcomes of court proceedings and/or compensation settlement negotiations. As well as continuing the constitutional challenge of the expropriation, Fortis is also pursuing alternative options for obtaining fair compensation, including compensation under the Belize/United Kingdom Bilateral Investment Treaty.

37. Contingencies

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Fortis

In May 2012 CH Energy Group and Fortis entered into a proposed settlement agreement with counsel to plaintiff shareholders pertaining to several complaints, which named Fortis and other defendants, which were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, relating to the acquisition of CH Energy Group by Fortis. The complaints generally alleged that the directors of CH Energy Group breached their fiduciary duties in connection with the acquisition and that CH Energy Group, Fortis, FortisUS Inc. and Cascade Acquisition Sub Inc. aided and abetted that breach. The settlement agreement is subject to court approval. In February 2014 the Supreme Court of the State of New York, County of New York, issued a Consent Order preliminarily certifying the matter as a class action and providing directions leading to a Settlement Hearing to be held in June 2014.

Following the announcement of the proposed acquisition of UNS Energy on December 11, 2013, several complaints, which named Fortis and other defendants, were filed in the Superior Court of Arizona, Pima County, and the United States District Court of the District of Arizona, challenging the proposed acquisition. The complaints generally allege that the directors of UNS Energy breached their fiduciary duties in connection with the proposed acquisition and that UNS Energy, Fortis, FortisUS Inc. and Color Acquisition Sub Inc. aided and abetted that breach.

The outcome of these lawsuits cannot be predicted with any certainty and, accordingly, no amount has been accrued in the consolidated financial statements. An adverse judgment for monetary damages could have a material adverse effect on the operations of the surviving company after the completion of the acquisition. A preliminary injunction could delay or jeopardize the completion of the acquisition and an adverse judgment granting permanent injunctive relief could indefinitely enjoin completion of the transaction. Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of such lawsuits is not expected to have a material adverse effect on the consolidated financial condition of Fortis. The defendants intend to vigorously defend themselves against the lawsuits.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FEI was the plaintiff in a British Columbia Supreme Court action against the City of Surrey ("Surrey") in which FEI sought the court's determination on the manner in which costs related to the relocation of a natural gas transmission pipeline would be shared between the Company and Surrey. The relocation was required due to the development and expansion of Surrey's transportation infrastructure. FEI claimed that the parties had an agreement that dealt with the allocation of costs. Surrey advanced counterclaims, including an allegation that FEI breached the agreement and that Surrey suffered damages as a result. In December 2013, the court issued a decision ordering FEI and Surrey to share equally the cost of the pipeline relocation. The court also decided that Surrey was successful in its counterclaim that FEI breached the agreement. The amount of damages that may be awarded to Surrey at a subsequent hearing cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake in 2003, prior to the acquisition of FortisBC Electric by Fortis, and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has disclosed that its claim includes approximately $15 million in damages as well as pre-judgment interest, but that it has not fully quantified its damages. FortisBC Electric and its insurers continue to defend the claim by the Government of British Columbia. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has not been served, the Company has retained counsel and has notified its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Central Hudson

Former MGP Facilities

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid- to late 1800s with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The New York State Department of Environmental Conservation ("DEC"), which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2013, an obligation of US$41 million was recognized in respect of MGP remediation and, based upon cost model analysis completed in 2012, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$152 million (Note 17).

37. Contingencies (cont'd)

Cental Hudson (cont'd)

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return (Note 7 *(vi)*).

Eltings Corners
Central Hudson owns and operates a maintenance and warehouse facility. In the course of Central Hudson's hazardous waste permit renewal process for this facility, sediment contamination was discovered within the wetland area across the street from the main property. Based on the investigation work completed by Central Hudson, the DEC and Central Hudson agreed in late 2013 that no additional investigation efforts are necessary. As requested by the DEC, Central Hudson submitted a draft Corrective Measures Study scoping document for review by the DEC. Although the extent of the contamination has now been established, the timing and costs for any future remediation efforts cannot be reasonably estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Asbestos Litigation
Prior to the acquisition of CH Energy Group, various asbestos lawsuits had been brought against Central Hudson. While a total of 3,342 asbestos cases have been raised, 1,170 remained pending as at December 31, 2013. Of the cases no longer pending against Central Hudson, 2,017 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 155 cases. The Company is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

38. Subsequent Events

Convertible Debentures Represented by Installment Receipts

To finance a portion of the pending acquisition of UNS Energy, in January 2014 Fortis, through a direct wholly owned subsidiary, completed the sale of $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures, represented by Installment Receipts (the "Debentures").

The offering of the Debentures consisted of a bought deal placement of $1.594 billion aggregate principal amount of Debentures underwritten by a syndicate of underwriters (the "Public Offering") and the sale of $206 million aggregate principal amount of Debentures to certain institutional investors on a private placement basis (together with the Public Offering, the "Offerings"). The overallotment option in connection with the Public Offering was not exercised.

The Debentures were sold on an installment basis at a price of $1,000 per Debenture, of which $333 was paid on closing of the Offerings and the remaining $667 is payable on a date ("Final Installment Date") to be fixed following satisfaction of all conditions precedent to the closing of the acquisition of UNS Energy. Prior to the Final Installment Date, the Debentures are represented by Installment Receipts. The Installment Receipts began trading on the TSX on January 9, 2014 under the symbol "FTS.IR". The Debentures will not be listed. The Debentures will mature on January 9, 2024 and bear interest at an annual rate of 4% per $1,000 principal amount of Debentures until and including the Final Installment Date, after which the interest rate will be 0%.

If the Final Installment Date occurs prior to the first anniversary of the closing of the Offerings, holders of Debentures who have paid the final installment will be entitled to receive, in addition to the payment of accrued and unpaid interest, an amount equal to the interest that would have accrued from the day following the Final Installment Date to, but excluding, the first anniversary of the closing of the Offerings had the Debentures remained outstanding until such date. As a result, in 2014 the Corporation expects to incur approximately $72 million ($51 million after tax) in financing costs associated with the Debentures.

At the option of the investors and provided that payment of the final installment has been made, each Debenture will be convertible into common shares of Fortis at any time after the Final Installment Date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per common share, being a conversion rate of 32.5521 common shares per $1,000 principal amount of Debentures.

The Debentures will not be redeemable except that Fortis will redeem the Debentures at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions necessary to approve the acquisition of UNS Energy will not be satisfied; (ii) termination of the acquisition agreement; and (iii) July 2, 2015, if notice of the Final Installment Date has not been given to investors on or before June 30, 2015. In addition, after the Final Installment Date, any Debentures not converted may be redeemed by Fortis at a price equal to their principal amount plus unpaid interest accrued prior to the Final Installment Date. Under the terms of the Installment Receipt Agreement, Fortis agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Installment Date has occurred, the Corporation will at all times maintain availability under its committed revolving corporate credit facility of not less than $600 million to cover the principal amount of the first installment of the Debentures in the event of a mandatory redemption.

At maturity, Fortis will have the right to pay the principal amount due in common shares, which will be valued at 95% of the weighted-average trading price on the TSX for the 20 consecutive trading days ending five trading days preceding the maturity date.

The net proceeds of the first installment of the Offerings was approximately $563 million. A significant portion of the net proceeds is cash on hand, while a portion was used to repay borrowings under the Corporation's existing revolving credit facility and for other general corporate purposes. The net proceeds of the final installment payment of the Offerings are expected to be, in aggregate, approximately $1.165 billion.

Sale of Griffith

In March 2014 CH Energy Group sold its non-regulated subsidiary, Griffith, for approximately US$70 million plus working capital.

39. Comparative Figures

Certain comparative figures have been reclassified to comply with current year presentation.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2013** [1]	2012 [1] [2]	2011 [1]
Revenue	**4,047**	3,654	3,738
Energy supply costs and operating expenses	**2,654**	2,390	2,547
Depreciation and amortization	**541**	470	416
Other income (expenses), net	**(31)**	4	38
Finance charges	**389**	366	363
Income taxes expense	**32**	61	84
Earnings from continuing operations	**400**	371	366
Extraordinary gain, net of tax	**20**	–	–
Net earnings	**420**	371	366
Net earnings attributable to non-controlling interests	**10**	9	9
Net earnings attributable to preference equity shareholders	**57**	47	46
Net earnings attributable to common equity shareholders	**353**	315	311
Balance Sheets *(in $ millions)*			
Current assets	**1,296**	1,093	1,132
Goodwill	**2,075**	1,568	1,565
Other long-term assets	**1,925**	1,715	1,580
Utility capital assets, non-utility capital assets and intangible assets	**12,612**	10,574	9,937
Total assets	**17,908**	14,950	14,214
Current liabilities	**2,084**	1,350	1,305
Other long-term liabilities	**3,024**	2,449	2,281
Long-term debt (excluding current portion)	**6,424**	5,741	5,685
Preference shares (classified as debt)	**–**	–	–
Total liabilities	**11,532**	9,540	9,271
Shareholders' equity	**6,376**	5,410	4,943
Cash Flows *(in $ millions)*			
Operating activities	**899**	992	915
Investing activities	**2,164**	1,096	1,115
Financing activities	**1,434**	396	386
Dividends, excluding dividends on preference shares classified as debt	**248**	225	206
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**8.06**	8.06	8.79
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease and finance obligations (net of cash)	**56.2**	55.3	57.1
Preference shares (classified as debt and equity)	**9.0**	9.7	8.3
Common shareholders' equity	**34.8**	35.0	34.6
Interest Coverage *(x)*			
Debt	**1.9**	2.0	2.0
All fixed charges	**1.9**	2.0	2.0
Total Gross Capital Expenditures *(in $ millions)*	**1,175**	1,146	1,171
Common Share Data			
Book value per share (year end) *($)*	**22.38**	20.84	20.25
Average common shares outstanding *(in millions)*	**202.5**	190.0	181.6
Basic earnings per common share *($)*	**1.74**	1.66	1.71
Dividends declared per common share *($)*	**1.25**	1.21	1.17
Dividends paid per common share *($)*	**1.24**	1.20	1.16
Dividend payout ratio *(%)*	**71.3**	72.3	67.8
Price earnings ratio *(x)*	**17.5**	20.6	19.5
Share Trading Summary (TSX)			
High price *($)*	**35.14**	34.98	35.45
Low price *($)*	**29.51**	31.70	28.24
Closing price *($)*	**30.45**	34.22	33.37
Volume *(in thousands)*	**120,470**	115,962	126,341

(1) Financial information for the years 2010 through 2013 prepared under US generally accepted accounting principles ("GAAP"); prior to 2010 prepared under Canadian GAAP.
(2) Certain 2012 comparative figures have been reclassified to comply with current year classifications.
(3) As at December 31, 2006, the regulatory provision for non-asset retirement obligation removal costs was reallocated from accumulated depreciation to long-term regulatory liabilities, with 2005 comparative figures restated, excluding an amount previously estimated for FortisBC Electric, due to a change in presentation adoped by FortisBC Electric effective December 31, 2009.

Historical Financial Summary

2010 [1]	2009	2008	2007	2006 [3]	2005 [3]	2004
3,647	3,641	3,907	2,718	1,472	1,441	1,146
2,448	2,577	2,859	1,904	939	926	766
406	364	348	273	178	158	114
13	10	–	8	2	10	–
359	369	363	299	168	154	122
72	49	65	36	32	70	47
375	292	272	214	157	143	97
–	–	–	–	–	–	–
375	292	272	214	157	143	97
10	12	13	15	8	6	6
45	18	14	6	2	–	–
320	262	245	193	147	137	91
1,205	1,124	1,150	1,038	405	299	293
1,561	1,560	1,575	1,544	661	512	514
1,309	917	487	424	331	471	418
9,336	8,538	7,954	7,276	4,049	3,315	2,713
13,411	12,139	11,166	10,282	5,446	4,597	3,938
1,491	1,592	1,697	1,804	558	412	538
1,977	1,325	763	732	508	503	164
5,616	5,239	4,848	4,588	2,532	2,110	1,879
–	320	320	320	320	320	320
9,084	8,476	7,628	7,444	3,918	3,345	2,901
4,327	3,663	3,538	2,838	1,528	1,252	1,037
742	681	661	373	263	304	272
980	1,045	852	2,033	634	467	1,026
451	563	387	1,826	456	224	777
189	176	191	146	77	64	51
10.06	8.41	8.70	10.00	11.87	12.40	11.28
60.4	60.2	59.5	64.3	61.1	58.7	61.4
8.7	6.9	7.3	5.2	10.0	8.6	9.4
30.9	32.9	33.2	30.5	28.9	32.7	29.2
2.0	1.9	1.9	1.9	2.2	2.5	2.3
2.0	1.8	1.8	1.7	2.0	2.1	2.0
1,071	1,024	935	803	500	446	279
18.65	18.61	17.97	16.69	12.19	11.74	10.45
172.9	170.2	157.4	137.6	103.6	101.8	84.7
1.85	1.54	1.56	1.40	1.42	1.35	1.07
1.41	0.78	1.01	0.88	0.70	0.61	0.55
1.12	1.04	1.00	0.82	0.67	0.59	0.54
60.5	67.5	64.1	58.6	47.2	43.7	50.3
18.4	18.6	15.8	20.7	21.0	18.0	16.2
34.54	29.24	29.94	30.00	30.00	25.64	17.75
21.60	21.52	20.70	24.50	20.36	17.00	14.23
33.98	28.68	24.59	28.99	29.77	24.27	17.38
120,855	121,162	132,108	100,920	60,094	37,706	29,254

Investor Information

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 16, 2014	August 15, 2014
November 18, 2014	February 17, 2015

Dividend Payment Dates

June 1, 2014	September 1, 2014
December 1, 2014	March 1, 2015

Earnings Release Dates

May 8, 2014	August 1, 2014
November 7, 2014	February 19, 2015

* *The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual Meeting

Wednesday, May 14, 2014
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")[(1)] and a Consumer Share Purchase Plan ("CSPP")[(2)] as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; First Preference Shares, Series K; and Installment Receipts of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.J, FTS.PR.K and FTS.IR, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

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Barry V. Perry
Vice President, Finance and Chief Financial Officer

Ronald W. McCabe
Vice President, General Counsel and Corporate Secretary

James D. Spinney
Treasurer

Jamie D. Roberts
Controller

Donna G. Hynes
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✷ Human Resources Committee
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For Board of Directors' biographies, please visit www.fortisinc.com.

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