

Management Discussion and Analysis

For the year ended December 31, 2015

Dated February 17, 2016

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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, 2015. Financial information for 2015 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”, “target”, “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 based on information currently available. The forward-looking information in the MD&A includes, but is not limited to, statements related to the acquisition of ITC Holdings Corp. (“ITC”), the expected timing and conditions precedent to the closing of the acquisition of ITC, including shareholder approvals of both ITC and Fortis, regulatory approvals, governmental approvals and other customary closing conditions; the expectation that Fortis will borrow funds to satisfy its obligation to pay the cash portion of the purchase price and will issue securities to pay the balance of the purchase price; the assumption of ITC debt and expected maintenance of investment-grade credit ratings; the impact of the acquisition on the Corporation’s earnings, midyear rate base, credit rating, estimated enterprise value and compound annual growth rate; the expectation that the acquisition of ITC will be accretive in the first full year following closing and that the acquisition will support the average annual dividend growth target of Fortis; the expectation that the Corporation will become a U.S. Securities and Exchange Commission registrant and have its common shares listed on the New York Stock Exchange in connection with the acquisition; the expectation that Fortis will identify one or more minority investors to invest in ITC; the annualized

2016 common share dividend; targeted annual dividend growth through 2020; the expectation that there will be a significant reduction in the use of coal in certain of UNS Energy's generating facilities by 2022; the acquisition of a share of Aitken Creek Gas Storage facility, the expected timing, total expected consideration and conditions precedent to the closing of such acquisition, including regulatory approval; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the expectation that midyear rate base will increase from 2016 to 2020; the Corporation's forecast gross consolidated capital expenditures for 2016 and total capital spending over the five-year period from 2016 through 2020; the nature, timing and expected costs of certain capital projects including, without limitation, the Tilbury liquefied natural gas ("LNG") facility expansion, the pipeline expansion to the Woodfibre LNG site, the development of a diesel power plant in Grand Cayman, the Residential Solar Program, the Gas Main Replacement Program, the Lower Mainland System Upgrade, the Pole Management Program, and additional opportunities including electric transmission, LNG and renewable related infrastructure and generation; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; 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 2016 capital expenditure programs, operating and interest costs, and dividend payments; the expected consolidated fixed-term debt maturities and repayments in 2016 and on average annually over the next five years; the expectation that long-term debt will not be settled prior to maturity; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to long 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 2016; the intent of management to hedge future exchange rate fluctuations and monitor its foreign currency exposure; the expectation that economic conditions in Arizona will improve; the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.

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; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the realization of additional opportunities including natural gas related infrastructure and generation; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; 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 electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; 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 and electricity 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, coal 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; new or revised environmental laws and regulations will not severely affect the results of operations; 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; that the Corporation can reasonably assess the merit of and potential liability attributable to ongoing legal proceedings; 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 2016 include, but are not limited to: uncertainty regarding the completion of the acquisition of ITC including but not limited to the receipt of shareholder approvals of ITC and Fortis, the receipt of regulatory and other governmental approvals, the availability of financing sources at the desired time or at all, on cost-efficient or commercially reasonable terms and the satisfaction or waiver of certain other conditions to closing; uncertainty related to the realization of some or all of the expected benefits of the acquisition of ITC; uncertainty regarding the outcome of regulatory proceedings of the Corporation's utilities; uncertainty of the impact a continuation of a low interest rate environment may have on the allowed rate of return on common shareholders' equity at the Corporation's regulated utilities; the impact of fluctuations in foreign exchange rates; and risk associated with the impact of less favorable economic conditions on the Corporation's results of operations.

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 a leader in the North American electric and gas utility business, with total assets of approximately \$29 billion and fiscal 2015 revenue of \$6.7 billion. The Corporation's asset mix is approximately 96% regulated (70% electric, 26% gas), with the remaining 4% comprised of long-term contracted hydroelectric operations. The Corporation's regulated utilities serve more than 3 million customers across Canada and in the United States and the Caribbean. In 2015 the Corporation's electricity distribution systems met a combined peak demand of 9,705 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,323 terajoules.

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 and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas 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. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When 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 prudently incurred costs and earn its allowed ROE or ROA.

Earnings of regulated utilities may be impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and common 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) regulatory lag in the case of a historical test year. When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of the 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.

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 assets, which are treated as a separate segment. 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 electric and gas utilities are as follows.

Regulated Electric & Gas Utilities - United States

- a. *UNS Energy*: Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively, the "UNS Utilities"), acquired by Fortis in August 2014.

TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 417,000 retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.

UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to approximately 94,000 retail customers in Arizona's Mohave and Santa Cruz counties.

TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,799 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2015, approximately 43% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility, serving approximately 152,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

- b. *Central Hudson*: Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving approximately 300,000 electricity customers and 79,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Regulated Gas Utility - Canadian

FortisBC Energy: Primarily includes FortisBC Energy Inc. ("FortisBC Energy" or "FEI") and, prior to December 31, 2014, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company. FEI is the largest distributor of natural gas in British Columbia, serving approximately 982,000 customers in more than 135 communities. Major areas served by the Company are the Lower Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities - Canadian

- a. *FortisAlberta*: FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 539,000 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 168,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 225 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 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"); the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT; and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT.

- c. *Eastern Canadian:* Comprised of Newfoundland Power Inc. (“Newfoundland Power”), Maritime Electric Company, Limited (“Maritime Electric”) and FortisOntario Inc. (“FortisOntario”). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 262,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island (“PEI”), serving approximately 78,000 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 primarily 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”).

Regulated Electric Utilities - Caribbean

The Regulated Electric Utilities – Caribbean segment includes the Corporation’s approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. (“Caribbean Utilities”) (December 31, 2014 - 60%), Fortis Turks and Caicos, and the Corporation’s 33% equity investment in Belize Electricity Limited (“Belize Electricity”). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 28,000 customers. The Company has an installed diesel-powered generating capacity of 132 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (“TSX”) (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities serving approximately 14,000 customers on certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

NON-REGULATED - FORTIS GENERATION

Fortis Generation is primarily comprised of long-term contracted generation assets in British Columbia and Belize. Generating assets in British Columbia include the Corporation’s 51% controlling ownership interest in the 335-MW Waneta Expansion. Construction of the Waneta Expansion was completed in April 2015 and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts. The Corporation’s 51% controlling ownership interest in the Waneta Expansion is conducted through the Waneta Expansion Limited Partnership (“Waneta Partnership”), with CPC/CBT holding the remaining 49% interest.

Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW. 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”).

As at December 31, 2015, the 16-MW run-of-river Walden hydroelectric generating facility has been classified as held for sale.

In June 2015 and July 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario, respectively.

NON-REGULATED - NON-UTILITY

The Non-Utility segment previously included Fortis Properties Corporation (“Fortis Properties”) and Griffith Energy Services, Inc. (“Griffith”). Fortis Properties completed the sale of its commercial real estate assets in June 2015 and its hotel assets in October 2015. For further information, refer to the “Significant Items” section of this MD&A. Griffith was sold in March 2014.

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 net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. and UNS Energy Corporation. 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 STRATEGY

The principal business of Fortis is the ownership and operation of regulated electric and gas utilities. The Corporation remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value. Earnings per common share and total shareholder return are the primary measures of financial performance.

Over the 10-year period ended December 31, 2015, earnings per common share of Fortis grew at a compound annual growth rate of 4.6%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 8.2%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 4.6% and 7.4%, respectively, over the same period.

The Corporation's first priority remains the continued profitable expansion of existing operations. Management remains focused on executing the consolidated capital program and pursuing additional investment opportunities within existing service territories. Fortis has also demonstrated its ability to acquire additional regulated utilities in Canada and the United States. The Corporation's standalone operating model and financial strength, driven by a strong balance sheet and investment-grade credit ratings, positions it well for future investment opportunities in existing and new franchise areas.

KEY TRENDS, RISKS AND OPPORTUNITIES

Pending Acquisition of ITC Holdings Corp.: On February 9, 2016, Fortis and ITC Holdings Corp. ("ITC") (NYSE:ITC) entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction (the "Acquisition") valued at approximately US\$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. For details on the Acquisition, including transaction details, strategic rationale and acquisition financing, refer to the "Subsequent Event" section of this MD&A, and for a discussion of risks associated with the Acquisition, refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" section of this MD&A.

Electric Utility Industry Developments: The North American electric utility industry has changed significantly over the past several years. The most notable changes include a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. At the same time, the continued low interest rate environment and decrease in world oil and gas prices are having significant impacts on the North American economy. Notwithstanding the changes occurring in the utility industry, safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of the utility industry's focus.

Government and regulatory policy in Canada and the United States is being directed at environmental protection and energy efficiency. The increasing availability of cleaner sources of power generation are driving new environmental regulation designed to eliminate or reduce dependence on traditional sources of electricity power generation, such as coal. The availability of cheaper, cleaner burning natural gas, as well as growing accessibility of renewable or alternative energy sources like solar are

encouraging governments to deploy aggressive targets for the removal of high carbon emission sources of energy. Reaching these targets will require the shutdown of certain high carbon emission generating plants earlier than planned, which is an issue that utilities and regulators need to address. These environmental regulations are, however, expected to create additional investment opportunities in renewable power generation and related energy infrastructure. Fortis' regulated utilities are actively involved in pursuing these opportunities.

Technological development, particularly in the area of distributed generation, is playing a significant role in the transformation of the utility industry. Although distributed generation customers remain connected to the electrical system and benefit from that connection, they avoid paying much of the fixed operating and maintenance costs because they can offset a portion of their volumetric energy usage with their own systems. This results in an increasing amount of utility costs that are ultimately shifted to other customers. The declining cost of certain types of distributed generation technologies, together with government subsidization, is encouraging increased adoption by customers. Not only does this expose the utility to declining revenue because of a decrease in energy sales, the rate structure serves to shift an increasing burden for these costs on those customers that do not have distributed generation, such as rooftop solar. Traditional rate designs have not been structured to ensure fairness among all customers, which is a focus for utilities and regulators. Fortis, through its subsidiaries, is working with its regulators to address these rate design issues for its customers.

Despite the challenges facing the utility industry, Fortis is well positioned to meet these headwinds and capitalize on any resulting opportunities. Its decentralized structure and customer focused business culture will support the efforts required to both meet evolving customer expectations and to work with policy makers and regulators on solutions that are financially sustainable for the utilities. Leveraging those relationships to get out in front of these evolving challenges will be essential to meeting the industry challenges.

Natural Gas Opportunities: FortisBC Energy continues to pursue opportunities in British Columbia related to gas infrastructure. The combination of an abundant supply of natural gas, low costs for natural gas and supportive government policy are generating new interest for large industrial customers and niche liquefied natural gas ("LNG") producers to utilize FortisBC Energy's gas system.

In 2013 the Government of British Columbia issued an Order in Council announcing the exemption of FEI's Tilbury LNG facility expansion ("Tilbury Expansion") from regulatory review. The Tilbury Expansion is well underway and will increase LNG production and storage capabilities, and is expected to be in service around the end of 2016. Since this announcement, there has been considerable interest for LNG supply from the Pacific Northwest, Hawaii, Alaska and international markets. In 2014 the Government of British Columbia issued a second Order in Council amending directions to the regulator regarding the Tilbury Expansion. The revisions set out a number of requirements for the regulator, including the consideration of a further expansion of the Tilbury site that would include additional liquefaction.

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 opportunities, additional capacity to connect to markets will have to be developed. FortisBC Energy continues to explore pipeline investment opportunities that include expansion of their existing distribution system to supply natural gas to a prospective LNG export facility, as well as to expand capacity on their Southern Crossing transmission pipeline. Specifically, FortisBC Energy is pursuing a potential pipeline expansion to the proposed Woodfibre LNG site in British Columbia. The Woodfibre LNG site is a former paper mill site located near Squamish, British Columbia. The Company has an opportunity to expand its gas pipeline and increase compression to deliver natural gas to this site.

For further information on the Corporation's natural gas investment opportunities, refer to the "Liquidity and Capital Resources – Additional Investment Opportunities" section of this MD&A.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's nine utilities is subject to regulation by the regulatory body in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level.

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

Central Hudson began operating under a new three-year rate order in mid-2015. In November 2015 TEP filed a general rate application ("GRA") with the Arizona Corporation Commission ("ACC") requesting new retail rates to be effective January 1, 2017, using the year ended June 30, 2015 as a historical test year. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US\$0.6 billion and the common equity component of capital structure increased from 43.5% to approximately 50%. The application also addresses rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service. In May 2015 UNS Electric filed a similar GRA requesting new retail rates effective May 1, 2016, using 2014 as a historical test year. The nature of UNS Electric's application was similar to that of TEP.

The Corporation's regulatory calendar for its utilities in Canada continues to be extensive. Newfoundland Power recently filed a GRA for 2016 and FortisBC Energy, the benchmark utility in British Columbia, filed its application to review cost of capital for 2016. In Alberta, while the regulator issued decisions on outstanding generic cost of capital proceedings and capital tracker applications early in 2015, it has initiated a generic cost of capital proceeding for 2016 and 2017, which includes FortisAlberta.

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

Capital Expenditure Program and Rate Base Growth: The Corporation's regulated midyear rate base for 2015 was \$16.4 billion. Over the five-year period through 2020, excluding the pending acquisition of ITC, the Corporation's capital program is expected to be approximately \$9 billion. This investment in energy infrastructure is expected to increase rate base to almost \$21 billion in 2020 and produce a five-year compound annual growth rate in rate base of approximately 5%. Fortis expects this capital investment to support growth in earnings and dividends.

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

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 usually issue debt at terms ranging between 5 and 40 years. As at December 31, 2015, almost 90% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately \$260 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 \$3.6 billion in credit facilities, of which approximately \$2.4 billion was unused as at December 31, 2015. 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 2016.

The Corporation has significant financing requirements associated with the pending acquisition of ITC. Refer to the “Business Risk Management – Risks Associated with the Acquisition of ITC” and “Subsequent Event” sections of this MD&A.

Dividend Increases: Dividends paid per common share increased to \$1.40 in 2015. During 2015 Fortis increased its quarterly dividend per common share over 17% to \$0.375 per quarter, or \$1.50 on an annualized basis. This continues the Corporation’s record of raising its annualized dividend to common shareholders for 42 consecutive years, the record for a public corporation in Canada.

Fortis also announced dividend guidance, targeting annual dividend per common share growth through 2020 of 6% based on a 2016 dividend of \$1.50. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its \$9 billion five-year capital expenditure plan, and management’s continued confidence in the strength of the Corporation’s diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance.

SIGNIFICANT ITEMS IN 2015

Pending Acquisition of Aitken Creek Gas Storage Facility: In December 2015 Fortis, through an indirect wholly owned subsidiary, entered into a definitive share purchase and sale agreement with Chevron Canada Properties Ltd. to acquire its share of the Aitken Creek Gas Storage Facility (“Aitken Creek”) for approximately US\$266 million, subject to customary closing conditions and adjustments. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada’s natural gas transmission network. The acquisition is subject to regulatory approval and is expected to close in the first half of 2016. The net cash purchase price is expected to be initially financed with borrowings under the Corporation’s credit facility. In December 2015 the Corporation paid a deposit of US\$29 million related to the transaction.

Sale of Commercial Real Estate and Hotel Assets: In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of \$430 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately \$109 million, net of expenses. As part of the transaction, Fortis subscribed to \$35 million in trust units of Slate Office REIT in conjunction with the REIT’s public offering.

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of \$365 million. As a result of the sale, the Corporation recognized an after-tax loss of approximately \$8 million, which reflects an impairment loss and expenses associated with the sale transaction.

Net proceeds from the sales were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy.

Sale of Non-Regulated Generation Assets in New York and Ontario: In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately \$77 million (US\$63 million). As a result of the sale, the Corporation recognized an after-tax gain of approximately \$27 million (US\$22 million), net of expenses and foreign exchange impacts.

In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of approximately \$16 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately \$5 million.

Settlement of Belize Electricity Expropriation Matters: In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the expropriation of the Corporation’s approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US\$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate \$9 million loss.

SUMMARY FINANCIAL HIGHLIGHTS

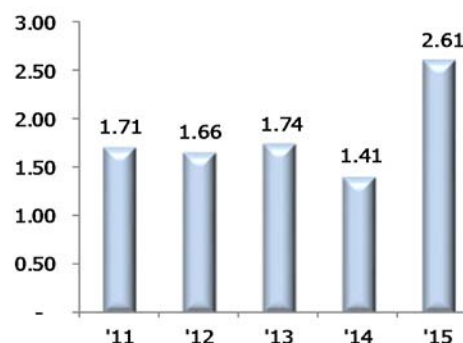
For the Years Ended December 31	2015	2014	Variance
Net Earnings Attributable to Common Equity Shareholders (\$ millions)	728	317	411
Basic Earnings per Common Share (\$)	2.61	1.41	1.20
Diluted Earnings per Common Share (\$)	2.59	1.40	1.19
Weighted Average Number of Common Shares Outstanding (millions)	278.6	225.6	53.0
Cash Flow from Operating Activities (\$ millions)	1,673	982	691
Dividends Paid per Common Share (\$)	1.40	1.28	0.12
Dividend Payout Ratio (%)	53.6	90.8	(37.2)
Return on Average Book Common Shareholders' Equity (%) ⁽¹⁾	9.8	5.4	4.4
Total Assets (\$ billions)	28.8	26.2	2.6
Gross Capital Expenditures (\$ billions)	2.2	1.7	0.5
Public Preference Share Offering (\$ billions)	-	0.6	(0.6)
Convertible Debenture Offering (\$ billions)	-	1.8	(1.8)
Long-Term Debt Offerings (\$ billions)	1.0	1.2	(0.2)

⁽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.

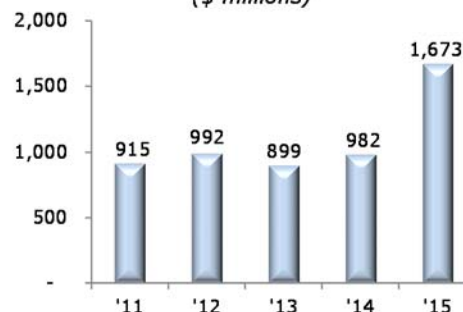
Net Earnings Attributable to Common Equity Shareholders:

Fortis achieved net earnings attributable to common equity shareholders of \$728 million in 2015 compared to \$317 million in 2014. On an adjusted basis, net earnings attributable to common equity shareholders for 2015 were \$589 million, an increase of \$195 million, or almost 50%, over 2014. Results for both years were impacted by non-recurring or adjusting items, which are detailed in the "Consolidated Results of Operations" section of this MD&A. The increase in adjusted net earnings attributable to common equity shareholders was driven by a full year's contribution from UNS Energy, which was acquired in mid-August 2014, earnings contribution from the Waneta Expansion, which came online in early April 2015, rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta, a higher allowance for funds used during construction ("AFUDC") at FortisBC Energy, the resetting of customer rates at Central Hudson, effective July 1, 2015, and the continued strength of the US dollar relative to the Canadian dollar. Earnings growth was tempered by an increase in Corporate expenses and lower earnings contribution due to the sale of the commercial real estate and hotel assets.

Basic Earnings per Common Share (\$)



Cash Flow from Operating Activities (\$ millions)



Basic Earnings per Common Share: Basic earnings per common share were \$2.61 in 2015 compared to \$1.41 in 2014. On an adjusted basis, as noted above, basic earnings per common share were \$2.11 for 2015, an increase of \$0.36 over 2014. The increase was driven by higher adjusted earnings per common share, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding.

Cash Flow from Operating Activities: Cash flow from operating activities was \$1,673 million for 2015, an increase of \$691 million, or 70%, over 2014. The increase was driven by higher cash earnings, mainly due to the factors noted above, and favourable changes in working capital.

Dividends: Dividends paid per common share increased to \$1.40 in 2015, 9.0% higher than \$1.28 in 2014. During 2015 Fortis increased its quarterly dividend per common share over 17% to \$0.375 per quarter. The Corporation's dividend payout ratio was 53.6% in 2015 compared to 90.8% in 2014. On an adjusted basis, the dividend payout ratio was 66.4% in 2015 compared to 73.1% in 2014.

Return on Average Book Common Shareholders Equity: The return on average book common shareholders' equity for 2015 was 9.8% compared to 5.4% for 2014. On an adjusted basis, the return on average book common shareholders' equity for 2015 was 7.9%, compared to 6.8% for 2014.

Total Assets: Total assets increased 9.9% to approximately \$28.8 billion at the end of 2015 compared to approximately \$26.2 billion at the end of 2014. The increase reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets in 2015.

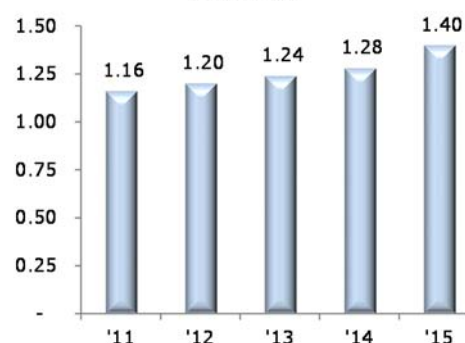
Gross Capital Expenditures: Consolidated capital expenditures, before customer contributions, were \$2.2 billion in 2015 compared to \$1.7 billion in 2014. The increase was driven by a full year contribution from UNS Energy and higher capital spending at most of the Corporation's regulated utilities, partially offset by lower non-regulated capital expenditures due to the completion of the Waneta Expansion and the sale of commercial real estate and hotel assets. For a detailed 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: The Corporation's regulated utilities raised approximately \$1 billion in long-term debt in 2015, largely in support of energy infrastructure investment and regularly scheduled debt repayments.

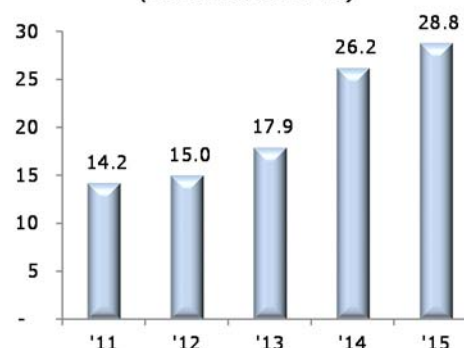
Fortis completed the sale of \$1.8 billion convertible debentures in 2014 to finance a portion of the acquisition of UNS Energy. In October 2014 approximately 58.2 million common shares of Fortis were issued on conversion of the debentures. In September 2014 Fortis issued 24 million First Preference Shares, Series M for gross proceeds of \$600 million. The net proceeds were also used to finance a portion of the acquisition of UNS Energy. The Corporation and its regulated utilities raised approximately \$1.2 billion in long-term debt in 2014.

For further information, refer to the "Liquidity and Capital Resources – Summary of Consolidated Cash Flows" section of this MD&A.

Dividends Paid per Common Share (\$)



Total Assets (\$ billions) (as at December 31)



CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31 (\$ millions)	2015	2014	Variance
Revenue	6,727	5,401	1,326
Energy Supply Costs	2,561	2,197	364
Operating Expenses	1,864	1,493	371
Depreciation and Amortization	873	688	185
Other Income (Expenses), Net	187	(25)	212
Finance Charges	553	547	6
Income Tax Expense	223	66	157
Earnings From Continuing Operations	840	385	455
Earnings From Discontinued Operations, Net of Tax	-	5	(5)
Net Earnings	840	390	450
Net Earnings Attributable to:			
Non-Controlling Interests	35	11	24
Preference Equity Shareholders	77	62	15
Common Equity Shareholders	728	317	411
Net Earnings	840	390	450

Revenue

The increase in revenue was driven by the acquisition of UNS Energy in August 2014. Favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion and higher base electricity rates at the Canadian Regulated Electric Utilities also contributed to the increase. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

Energy Supply Costs

The increase in energy supply costs was primarily due to the acquisition of UNS Energy and unfavourable foreign exchange associated with the translation of US dollar-denominated energy supply costs. The increase was partially offset by lower commodity costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities.

Operating Expenses

The increase in operating expenses was primarily due to the acquisition of UNS Energy, unfavourable foreign exchange associated with the translation of US dollar-denominated operating expenses and general inflationary and employee-related cost increases. The increase was partially offset by a decrease in non-utility operating expenses due to the sale of commercial real estate and hotel assets, and lower Corporate retirement expenses.

Depreciation and Amortization

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

Other Income (Expenses), Net

The increase in other income, net of expenses, was driven by gains on the sale of commercial real estate and non-regulated generation assets in 2015, compared to acquisition-related expenses associated with UNS Energy in 2014. The increase was partially offset by a loss associated with the sale of hotel assets in 2015.

Finance Charges

The increase in finance charges was primarily due to the acquisition of UNS Energy, including interest expense on debt issued to complete the financing of the acquisition, and unfavourable foreign exchange associated with the translation of US-dollar denominated interest expense. The increase was partially offset by lower interest on convertible debentures. Approximately \$72 million (\$51 million after tax) in interest expense was recognized in 2014 associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy. In October 2014 the convertible debentures were substantially all converted into common shares of the Corporation.

Income Tax Expense

The increase in income tax expense was primarily due to higher earnings before income taxes, driven by the acquisition of UNS Energy and gains on the sale of commercial real estate and non-regulated generation assets in 2015, and a higher effective income tax rate, mainly due to the combined federal and state income tax rate at UNS Energy.

Net Earnings Attributable to Common Equity Shareholders and Basic Earnings Per Common Share

Net earnings attributable to common equity shareholders were impacted by a number of non-recurring or non-operating items. These items, referred to as adjusting items, are reconciled below and discussed in the segmented results of operations for the respective reporting segments. Management believes that adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share provide useful information to investors and shareholders as they provide increased transparency and predictive value. The adjusting items do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. Therefore, these adjusting items may not be comparable with similar measures presented by other companies.

Non-US GAAP Reconciliation			
Years Ended December 31			
<i>(\$ millions, except for common share data)</i>			
	2015	2014	Variance
Net Earnings Attributable to Common Equity Shareholders	728	317	411
Adjusting Items:			
FortisAlberta -			
Capital tracker revenue adjustment for 2013 and 2014	(9)	-	(9)
Non-Regulated - Fortis Generation -			
Gain on sale of generation assets	(32)	-	(32)
Non-Utility -			
Gain on sale of commercial real estate assets	(109)	-	(109)
Loss on sale of hotel assets	8	-	8
Earnings from discontinued operations	-	(5)	5
Corporate and Other -			
Foreign exchange gain	(13)	(8)	(5)
Loss on settlement of expropriation matters	9	-	9
Interest expense on convertible debentures	-	51	(51)
Acquisition-related expenses	7	39	(32)
Adjusted Net Earnings Attributable to Common Equity Shareholders	589	394	195
Adjusted Basic Earnings Per Common Share (\$)	2.11	1.75	0.36

Adjusted Net Earnings Attributable to Common Equity Shareholders

The increase in adjusted net earnings attributable to common equity shareholders was driven by earnings contribution of \$195 million at UNS Energy compared to \$60 million for 2014. Earnings contribution of \$22 million from the Waneta Expansion, which represents the Corporation's 51% controlling ownership interest, also contributed to the increase. Performance was driven by all of the Corporation's other regulated utilities, including rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta; a higher AFUDC at FortisBC Energy; and improved performance at Central Hudson under a new three-year rate order. Favourable foreign exchange impacts associated with US dollar-denominated earnings also increased earnings year over year. The increase in adjusted earnings was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy, and lower earnings contribution from non-utility assets due to the sale of commercial real estate and hotel assets.

Adjusted Basic Earnings Per Common Share

The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of UNS Energy, after considering the finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding, and contribution from the Waneta Expansion. Performance at all of the Corporation's other regulated utilities, as discussed above, and the impact of favourable foreign exchange also contributed to the increase. The increase was partially offset by an increase in Corporate expenses and lower earnings contribution from non-utility assets due to the sale of commercial real estate and hotel assets.

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders			
Years Ended December 31			
<i>(\$ millions)</i>	2015	2014	Variance
Regulated Electric & Gas Utilities - United States			
UNS Energy	195	60	135
Central Hudson	58	37	21
	253	97	156
Regulated Gas Utility - Canadian			
FortisBC Energy	140	127	13
Regulated Electric Utilities - Canadian			
FortisAlberta	138	103	35
FortisBC Electric	50	46	4
Eastern Canadian	62	60	2
	250	209	41
Regulated Electric Utilities - Caribbean	34	27	7
Non-Regulated - Fortis Generation	77	20	57
Non-Regulated - Non-Utility	114	28	86
Corporate and Other	(140)	(191)	51
Net Earnings Attributable to Common Equity Shareholders	728	317	411

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.

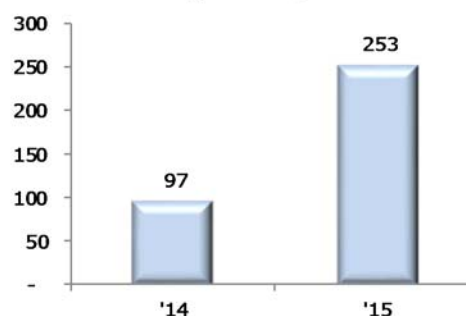
REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2015 earnings from regulated assets represented approximately 92% (2014 – 91%) of the Corporation's earnings from its operating segments (excluding Corporate and Other segment expenses), excluding the gains on sale of non-core assets. Total regulated assets represented 96% of the Corporation's total assets as at December 31, 2015 (December 31, 2014 – 93%).

REGULATED ELECTRIC & GAS UTILITIES – UNITED STATES

Regulated Electric & Gas Utilities - United States earnings for 2015 were \$253 million (2014 - \$97 million), which represented approximately 37% (2014 - 21%) of the Corporation's total regulated earnings. Total segment assets were approximately \$12.1 billion as at December 31, 2015 (December 31, 2014 - \$9.9 billion), which represented approximately 44% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 - 40%).

Regulated Electric & Gas Utilities - United States Earnings (\$ millions)



UNS ENERGY

Financial Highlights ⁽¹⁾		
Years Ended December 31	2015	2014
Average US:CAD Exchange Rate ⁽²⁾	1.28	1.12
Electricity Sales (<i>gigawatt hours ("GWh")</i>)	15,366	5,646
Gas Volumes (<i>petajoules ("PJ")</i>)	13	5
Revenue (<i>\$ millions</i>)	2,034	684
Earnings (<i>\$ millions</i>)	195	60

⁽¹⁾ Financial results of UNS Energy are from August 15, 2014, the date of acquisition.

⁽²⁾ The reporting currency of UNS Energy is the US dollar. The average US:CAD exchange rate for 2014 is from the date of acquisition.

Electricity Sales & Gas Volumes

Electricity sales were 15,366 gigawatt hours ("GWh") for 2015 compared to 14,560 GWh for the full year in 2014. The increase was primarily due to higher short-term wholesale electricity sales. The majority of short-term wholesale electricity sales is flowed through to customers and has no impact on earnings. Retail sales were comparable year over year.

Gas volumes of 13 petajoules ("PJ") for 2015 were comparable with the full year in 2014.

Revenue

Revenue was US\$1,588 million for 2015 compared to US\$1,560 million for the full year in 2014. The increase was primarily due to the flow through to customers of higher purchased power and fuel supply costs, higher transmission revenue, and higher wholesale electricity sales. On a Canadian dollar basis, revenue was also impacted by favourable foreign exchange.

Earnings

Earnings were US\$152 million for 2015 compared to US\$144 million for the full year in 2014, excluding the impact of acquisition-related expenses. The increase was primarily due to higher transmission revenue and a decrease in interest expense due to the expiry of leasing arrangements. The increase was partially offset by higher operating expenses. On a Canadian dollar basis, earnings were also impacted by favourable foreign exchange.

CENTRAL HUDSON

Financial Highlights			
Years Ended December 31	2015	2014	Variance
Average US:CAD Exchange Rate ⁽¹⁾	1.28	1.10	0.18
Electricity Sales (GWh)	5,132	5,075	57
Gas Volumes (PJ)	24	23	1
Revenue (\$ millions)	880	821	59
Earnings (\$ millions)	58	37	21

⁽¹⁾ The reporting currency of Central Hudson is the US dollar.

Electricity Sales & Gas Volumes

The increase in electricity sales was mainly due to higher average consumption as a result of warmer temperatures in the summer, which increased the use of air conditioning and other cooling equipment. Gas volumes for 2015 were comparable with last year.

Changes in electricity sales and gas volumes at Central Hudson are subject to regulatory revenue decoupling mechanisms and, as a result, do not have a material impact on revenue and earnings.

Revenue

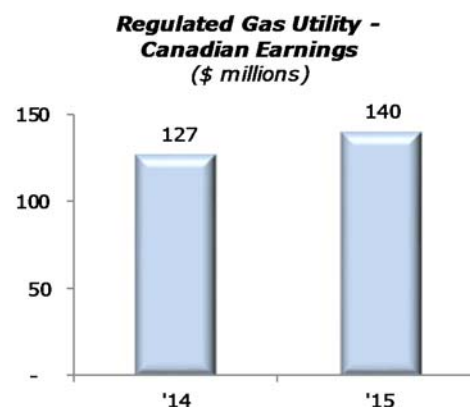
The increase in revenue was driven by approximately \$111 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue. An increase in base electricity rates effective July 1, 2015 and the recovery from customers of previously deferred electricity costs also contributed to the increase in revenue. Additionally, revenue for the first half of 2015 was favourably impacted by energy efficiency incentives and higher gas revenue associated with a new gas delivery contract in late 2014. The increase was partially offset by the recovery from customers of lower commodity costs, which were mainly due to lower wholesale prices.

Earnings

The increase in earnings was primarily due to approximately \$9 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, an increase in base electricity rates effective July 1, 2015, a new gas delivery contract implemented in late 2014, and energy efficiency incentives earned during the first half of 2015. The increase was partially offset by the impact of higher expenses during the two-year rate freeze period post acquisition, which ended on June 30, 2015.

REGULATED GAS UTILITY – CANADIAN

Regulated Gas Utility - Canadian earnings for 2015 were \$140 million (2014 - \$127 million), which represented approximately 21% of the Corporation's total regulated earnings (2014 - 28%). Total segment assets were approximately \$6.0 billion as at December 31, 2015 (December 31, 2014 - \$5.8 billion), which represented approximately 22% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 - 24%).



FORTISBC ENERGY

Financial Highlights			
Years Ended December 31	2015	2014	Variance
Gas Volumes (<i>PJ</i>)	186	195	(9)
Revenue (<i>\$ millions</i>)	1,295	1,435	(140)
Earnings (<i>\$ millions</i>)	140	127	13

Gas Volumes

The decrease in gas volumes was primarily due to lower average consumption in the first quarter as a result of warmer temperatures.

FortisBC Energy earns 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 regulatory deferral mechanisms, changes in consumption levels and the cost of natural gas from those forecast to set customer gas rates do not materially affect earnings.

Revenue

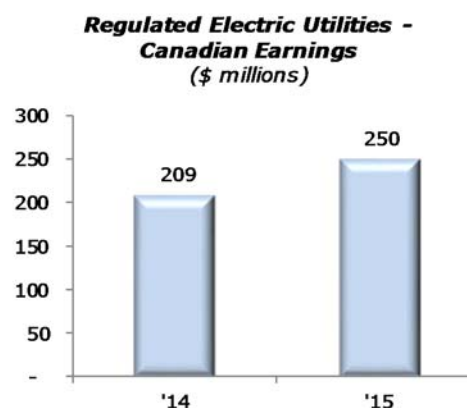
The decrease in revenue was primarily due to a lower commodity cost of natural gas charged to customers and lower gas volumes. The decrease was partially offset by higher regulatory flow-through deferral amounts.

Earnings

The increase in earnings was mainly due to higher AFUDC, regulatory flow-through deferral amounts and operating cost savings, net of the earnings sharing mechanism. The increase was partially offset by a decrease in the allowed ROE and equity component of capital structure as a result of the amalgamation of FEVI and FEWI with FEI, effective December 31, 2014. For further details on the amalgamation, refer to the “Material Regulatory Decisions and Applications” section of this MD&A.

REGULATED ELECTRIC UTILITIES - CANADIAN

Regulated Electric Utilities - Canadian earnings for 2015 were \$250 million (2014 - \$209 million), which represented approximately 37% of the Corporation’s total regulated earnings (2014 – 45%). Total segment assets were approximately \$8.2 billion as at December 31, 2015 (December 31, 2014 - \$7.7 billion), which represented approximately 30% of the Corporation’s total regulated assets as at December 31, 2015 (December 31, 2014 – 32%).



FORTISALBERTA

Financial Highlights			
Years Ended December 31	2015	2014	Variance
Energy Deliveries (<i>GWh</i>)	17,132	17,372	(240)
Revenue (<i>\$ millions</i>)	563	518	45
Earnings (<i>\$ millions</i>)	138	103	35

Energy Deliveries

The decrease in energy deliveries was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas, partially offset by higher average consumption by farm and irrigation, residential and commercial customers. Lower levels of precipitation, particularly in the third quarter, and warmer temperatures had a favorable impact on energy deliveries to farm and irrigation customers. Higher energy deliveries to residential and commercial customers due to customer growth were partially offset by lower average consumption due to warmer temperatures.

Revenue

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.

The increase in revenue was primarily due to the operation of the PBR formula, including an increase in customer rates based on a combined inflation and productivity factor of 1.49%, higher capital tracker revenue, growth in the number of customers, and higher revenue related to flow-through costs to customers. Revenue was also favourably impacted by a \$9 million capital tracker revenue adjustment recognized in 2015 associated with 2013 and 2014, as a result of regulatory decisions. For further details on regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Earnings

The increase in earnings was primarily due to rate base growth associated with capital expenditures, growth in the number of customers, and the impact of a technical update on depreciation and amortization. Also contributing to the increase in earnings was capital tracker revenue of approximately \$9 million recognized in 2015 associated with 2013 and 2014, as discussed above.

FORTISBC ELECTRIC

Financial Highlights			
Years Ended December 31	2015	2014	Variance
Electricity Sales (<i>GWh</i>)	3,116	3,179	(63)
Revenue (<i>\$ millions</i>)	360	334	26
Earnings (<i>\$ millions</i>)	50	46	4

Electricity Sales

The decrease in electricity sales was primarily due to lower average consumption in the first and fourth quarters as a result of warmer temperatures.

Revenue

The increase in revenue was driven by increases in base electricity rates, mainly established to recover higher power purchase costs, and surplus capacity sales. Revenue was also favourably impacted by higher contribution from non-regulated operating, maintenance and management services associated with the Waneta Expansion. The increase was partially offset by lower electricity sales.

Earnings

The increase in earnings was primarily due to higher earnings from non-regulated operating, maintenance and management services, and rate base growth.

EASTERN CANADIAN ELECTRIC UTILITIES

Financial Highlights			
Years Ended December 31	2015	2014	Variance
Electricity Sales (<i>GWh</i>)	8,403	8,376	27
Revenue (<i>\$ millions</i>)	1,033	1,008	25
Earnings (<i>\$ millions</i>)	62	60	2

Electricity Sales

The increase in electricity sales was primarily due to customer growth in Newfoundland, as well as higher average consumption in PEI, mainly due to an increase in the number of customers using electricity for home heating. The increase was partially offset by lower electricity sales in Ontario, largely due to the loss of a commercial customer and lower average consumption by residential customers due to changes in temperatures.

Revenue

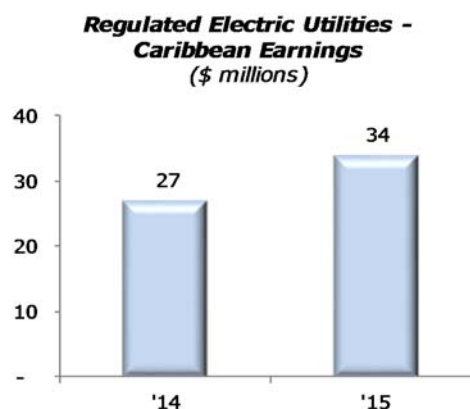
The increase in revenue was mainly due to the flow through in customer electricity rates of overall higher energy supply costs and electricity sales growth.

Earnings

The increase in earnings was primarily due to electricity sales growth and lower operating costs, mainly due to restoration efforts at Newfoundland Power following the loss of energy supply from Newfoundland and Labrador Hydro (“Newfoundland Hydro”) and related power interruptions in January 2014, partially offset by higher depreciation expense.

REGULATED ELECTRIC UTILITIES - CARIBBEAN

Regulated Electric Utilities - Caribbean earnings for 2015 were \$34 million (2014 - \$27 million), which represented approximately 5% of the Corporation’s total regulated earnings (2014 – 6%). Total segment assets were approximately \$1.3 billion as at December 31, 2015 (December 31, 2014 - \$1.1 billion), which represented approximately 4% of the Corporation’s total regulated assets as at December 31, 2015 (December 31, 2014 – 4%).



Financial Highlights			
Years Ended December 31	2015	2014	Variance
Average US:CAD Exchange Rate ⁽¹⁾	1.28	1.10	0.18
Electricity Sales (GWh)	802	771	31
Revenue (\$ millions)	321	321	-
Earnings (\$ millions)	34	27	7

⁽¹⁾ The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ\$2.00=US\$1.00.

Electricity Sales

The increase in electricity sales was primarily due to growth in the number of customers as a result of increased economic activity and overall warmer temperatures, which increased air conditioning load.

Revenue

Revenue was impacted by approximately \$39 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, and electricity sales growth. The increase was largely offset by the flow through in customer electricity rates of lower fuel costs at Caribbean Utilities.

Earnings

The increase in earnings was due to approximately \$5 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, electricity sales growth and higher capitalized interest at Caribbean Utilities. The increase was partially offset by higher depreciation. Equity income from Belize Electricity from the date of settlement in August 2015 was less than \$1 million.

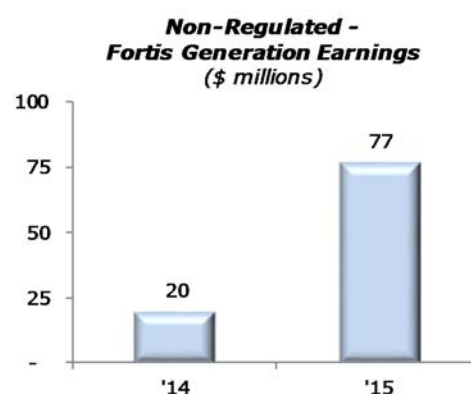
NON-REGULATED

NON-REGULATED - FORTIS GENERATION

Financial Highlights			
Years Ended December 31	2015	2014	Variance
Energy Sales (GWh)	844	407	437
Revenue (\$ millions)	107	38	69
Earnings (\$ millions)	77	20	57

Energy Sales

The increase in energy sales was driven by the Waneta Expansion, which commenced production in early April 2015 and reported energy sales of 517 GWh in 2015. The increase was partially offset by decreased production in Belize due to lower rainfall and in Upstate New York and Ontario due to the sale of generation assets in mid 2015, lower rainfall, and generating units taken out of service for repairs.



Revenue

The increase in revenue was driven by the Waneta Expansion, which recognized revenue of \$70 million in 2015, and approximately \$4 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue. The increase was partially offset by decreased production in Belize, Upstate New York and Ontario.

Earnings

The increase in earnings was driven by the recognition of after-tax gains totalling approximately \$32 million on the sale of generation assets in Upstate New York and Ontario in mid 2015, and earnings contribution of \$22 million from the Waneta Expansion. Approximately \$3 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings and lower business development costs were partially offset by decreased production in Belize, Upstate New York and Ontario.

NON-REGULATED – NON-UTILITY

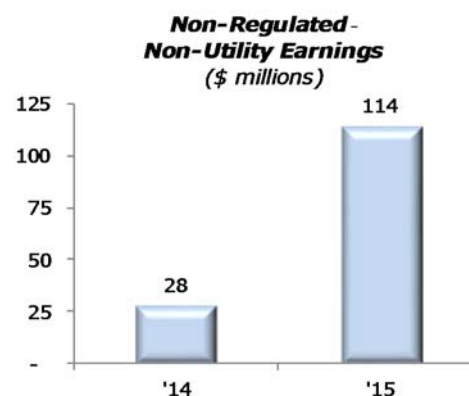
Financial Highlights			
Years Ended December 31			
(\$ millions)	2015	2014	Variance
Revenue	171	249	(78)
Earnings	114	28	86

Revenue

The decrease in revenue was primarily due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

Earnings

The increase in earnings was driven by a net after-tax gain of approximately \$101 million on the sale of commercial real estate and hotel assets. The increase was partially offset by lower earnings contribution from the commercial real estate and hotel assets as a result of the sale and \$5 million in earnings in 2014 associated with Griffith from normal operations to the date of sale in March 2014.



CORPORATE AND OTHER

Financial Highlights			
Years Ended December 31			
<i>(\$ millions)</i>	2015	2014	Variance
Revenue	24	31	(7)
Operating Expenses	26	38	(12)
Depreciation and Amortization	2	2	-
Other Income (Expenses), Net	(8)	(45)	37
Finance Charges	94	154	(60)
Income Tax Recovery	(43)	(79)	36
	(63)	(129)	66
Preference Share Dividends	77	62	15
Net Corporate and Other Expenses	(140)	(191)	51

Net Corporate and Other expenses were impacted by the following items.

- (i) A foreign exchange gain of \$13 million in 2015 compared to \$8 million in 2014, associated with the Corporation's previous US-dollar denominated long-term other asset that represented the book value of its expropriated investment in Belize Electricity, which was included in other income;
- (ii) A loss of approximately \$9 million in 2015 on settlement of expropriation matters related to the Corporation's investment in Belize Electricity, which was included in other income, net of expenses;
- (iii) Acquisition-related expenses of \$10 million (\$7 million after tax) in 2015 associated with the pending acquisition of ITC, which were included in other income;
- (iv) Finance charges of \$72 million (\$51 million after tax) in 2014 associated with the convertible debentures issued to finance a portion of the acquisition of UNS Energy; and
- (v) Other expenses of approximately \$58 million (\$39 million after tax) in 2014 related to the acquisition of UNS Energy.

Excluding the above-noted items, net Corporate and Other expenses were \$137 million for 2015 compared to approximately \$109 million for 2014. The increase in net Corporate and Other expenses was primarily due to higher preference share dividends and finance charges, and a decrease in revenue. The increase was partially offset by lower operating expenses.

The increase in preference share dividends and finance charges was primarily due to the acquisition of UNS Energy. Finance charges were also impacted by no longer capitalizing interest upon completion of the Waneta Expansion and unfavourable foreign exchange associated with the translation of US-dollar denominated interest expense.

The decrease in revenue was primarily due to a decrease in related-party interest income, mainly due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

The decrease in operating expenses was primarily due to lower retirement expenses. Retirement expenses of approximately \$13 million (\$11 million after tax) were recognized in 2014 compared to approximately \$2 million (\$1 million after tax) in 2015. The decrease in operating expenses was partially offset by a \$3 million (\$2 million after tax) corporate donation recognized in 2015.

REGULATORY HIGHLIGHTS

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

NATURE OF REGULATION

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%)			Significant Features Future or Historical Test Year Used to Set Customer Rates
			2014	2015	2016	
TEP	ACC	43.5	10.00	10.00	10.00	COS/ROE ⁽¹⁾
UNS Electric	ACC	52.6 ⁽²⁾	9.50	9.50	9.50 ⁽²⁾	ROEs established by the ACC
UNS Gas	ACC	50.8	9.75	9.75	9.75	
Central Hudson	New York State Public Service Commission ("PSC")	48	10.00	10.00/9.00 ⁽²⁾	9.00	Historical Test Year COS/ROE Earnings sharing mechanism ROE established by the PSC Future Test Year
FEI	British Columbia Utilities Commission ("BCUC")	38.5 ⁽²⁾	8.75	8.75	8.75 ⁽²⁾	COS/ROE PBR mechanism for 2014 through 2019
FEVI	BCUC	41.5 ⁽⁴⁾	9.25	n/a ⁽⁴⁾	n/a ⁽⁴⁾	ROEs established by the BCUC
FEWI	BCUC	41.5 ⁽⁴⁾	9.50	n/a ⁽⁴⁾	n/a ⁽⁴⁾	
FortisBC Electric	BCUC	40 ⁽²⁾	9.15	9.15	9.15 ⁽²⁾	2013 test year with 2014 through 2019 rates set using PBR mechanism COS/ROE PBR mechanism for 2014 through 2019 ROE established by the BCUC 2013 test year with 2014 through 2019 rates set using PBR mechanism
FortisAlberta	Alberta Utilities Commission ("AUC")	40 ⁽²⁾	8.30	8.30	8.30 ⁽²⁾	COS/ROE PBR mechanism for 2013 through 2017 with capital tracker account and other supportive features ROE established by the AUC 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 ⁽²⁾	8.80 +/- 50 bps	8.80 +/- 50 bps	8.80 +/- 50 bps ⁽²⁾	COS/ROE ROE established by the PUB Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40 ⁽²⁾	9.75	9.75	9.35 ⁽²⁾	COS/ROE ROE established by the PEI Energy Accord in 2014 and 2015. ROE in 2016 to be established by IRAC Future Test Year
FortisOntario	Ontario Energy Board	40	8.93 - 9.85	8.93 - 9.30	8.93 - 9.30	COS/ROE ⁽⁵⁾ Future test year and incentive regulation rate-setting mechanism
Caribbean Utilities	Electricity Regulatory Authority	N/A	7.00 - 9.00	7.25 - 9.25	6.75 - 8.75	ROA COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Historical Test Year
Fortis Turks and Caicos	Government of the Turks and Caicos Islands	N/A	15.00 - 17.50 ⁽⁶⁾	15.00 - 17.50 ⁽⁶⁾	15.00 - 17.50 ⁽⁶⁾	COS/ROA Historical Test Year

⁽¹⁾ Additionally, allowed ROEs are adjusted for the fair value of rate base as required under the laws of the State of Arizona.

⁽²⁾ Interim and subject to change pending the outcome of regulatory proceedings effective January 1, 2016 for FortisAlberta, FEI and FortisBC Electric; May 1, 2016 for UNS Electric; July 1, 2016 for Newfoundland Power; and March 1, 2016 for Maritime Electric.

⁽³⁾ Allowed ROE of 10.0% with a 48% common equity component of capital structure to June 30, 2015. Allowed ROE of 9.00% with a 48% common equity component of capital structure effective July 1, 2015 through June 30, 2018.

⁽⁴⁾ As approved by the BCUC, effective December 31, 2014, FEVI and FEWI were amalgamated with FEI and, as a result, the allowed ROE and common equity component of capital structure for 2015 reverted to those of FEI.

⁽⁵⁾ Cornwall Electric is subject to a rate-setting mechanism under a Franchise Agreement with the City of Cornwall, based on a price cap with commodity cost flow through.

⁽⁶⁾ Achieved ROAs at the utilities are 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.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS

The following summarizes the significant regulatory decisions and applications for the Corporation's regulated utilities for 2015.

UNS Energy

In November 2015 TEP, UNS Energy's largest utility, filed a GRA with the ACC requesting new retail rates to be effective January 1, 2017, using the year ended June 30, 2015 as a historical test year. The key provisions of the rate request include: (i) a base retail rate increase of US\$110 million, or 12.0%, compared with adjusted test year revenue; (ii) a 7.34% return on original cost rate base of US\$2.1 billion; (iii) a common equity component of capital structure of approximately 50%; (iv) a cost of equity of 10.35% and an average cost of debt of 4.32%; and (v) rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US\$0.6 billion and the common equity component of capital structure increased from 43.5% to approximately 50%. In May 2015 UNS Electric filed a GRA requesting new retail rates to be effective May 1, 2016, using 2014 as a historical test year. The nature of UNS Electric's GRA was similar to that of TEP. A decision on UNS Electric's application is expected in the third quarter of 2016 and TEP's application is expected in the fourth quarter of 2016.

Central Hudson

Three-Year Rate Order

In June 2015 the PSC issued a Rate Order for Central Hudson covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. A delivery rate freeze was implemented for electricity and natural gas delivery rates through June 30, 2015 as part of the regulatory approval of the acquisition of Central Hudson by Fortis. Central Hudson invested approximately US\$225 million in energy infrastructure during the two-year delivery rate freeze period ended June 30, 2015. The approved Rate Order reflects an allowed ROE of 9.0% and a 48% common equity component of capital structure. The Rate Order includes capital investments of approximately US\$490 million during the three-year period targeted at making the electric and gas systems stronger.

The approved Rate Order includes full cost recovery of electric and natural gas commodity costs and continuation of certain mechanisms, including revenue decoupling and earnings sharing mechanisms. In the approved earnings sharing mechanism, the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer. In addition, the Rate Order includes a major storm reserve for electric operations and provides for continuation of recovery of various operating expenses, including environmental site investigation and remediation costs. To the extent that Central Hudson receives gas delivery revenue associated with a new contract implemented in late 2014, associated revenue is being used to mitigate future gas customer rate increases, effective July 1, 2015.

Reforming the Energy Vision

In 2014 the PSC issued an order instituting a proceeding to reform New York State's electricity industry and regulatory practices ("Reforming the Energy Vision"). The initiative seeks to further a number of policy objectives and seeks to determine the appropriate role of electric distribution utilities in furthering these objectives, as well as considering regulatory changes to better align utility interest with energy policy objectives. In 2015 Central Hudson continued to fully participate in this proceeding. The outcome of Reforming the Energy Vision cannot be determined at this time and it could impact the scope of regulated utilities in New York State.

FortisBC Energy and FortisBC Electric

Multi-Year PBR Plans

In September 2014 the BCUC issued its decisions on FEI and FortisBC Electric's Multi-Year PBR Plans for 2014 through 2019. The approved PBR Plans incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FEI and

1.03% for FortisBC Electric each year. The approved PBR Plans also include a 50%/50% sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI and FortisBC Electric maintain service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between the utilities and interested parties regarding current performance and future activities.

In May 2015 and June 2015, the BCUC issued its decisions on FEI and FortisBC Electric's 2015 rates in compliance with the PBR decisions issued in September 2014. The decisions approved 2015 midyear rate base of approximately \$3,661 million and \$1,249 million for FEI and FortisBC Electric, respectively, and approved customer rate increases for 2015 of 0.7% and 4.2% over 2014 rates, respectively.

In December 2015 the BCUC issued its decisions on FEI and FortisBC Electric's 2016 rates. The decisions approved 2016 midyear rate base of approximately \$3,693 million and \$1,286 million for FEI and FortisBC Electric, respectively, and approved customer rate increases for 2016 of 1.79% and 2.96% over 2015 rates, respectively.

Generic Cost of Capital Proceedings

A Generic Cost of Capital ("GCOC") Proceeding to establish the allowed ROE and capital structures for regulated utilities in British Columbia occurred from 2012 through 2014. FEI was designated as the benchmark utility and a BCUC decision established that the ROE for the benchmark utility would be set at 8.75% with a 38.5% common equity component of capital structure, both effective January 1, 2013 through December 31, 2015. The GCOC Proceeding reaffirmed for FortisBC Electric a risk premium over the benchmark utility of 40 basis points, resulting in an allowed ROE of 9.15% effective January 1, 2013 through December 31, 2015, and a common equity component of capital structure at 40%.

The BCUC decision directed FEI to file an application to review the 2016 benchmark utility ROE and common equity component of capital structure. In October 2015, as required by the regulator, FEI filed its application to review the 2016 benchmark allowed ROE and common equity component of capital structure. As FEI is the benchmark utility, the review of the application could also have an impact on FortisBC Electric. A decision on the application is expected in the second quarter of 2016.

FortisAlberta

Generic Cost of Capital Proceedings

In March 2015 the AUC issued its decision on the GCOC Proceeding in Alberta. The GCOC Proceeding set FortisAlberta's allowed ROE for 2013 through 2015 at 8.30%, down from the interim allowed ROE of 8.75%, and set the common equity component of capital structure at 40%, down from 41%. The AUC also determined that it would not re-establish a formula-based approach to setting the allowed ROE at this time. Instead, the allowed ROE of 8.30% and common equity component of capital structure of 40% will remain in effect on an interim basis for 2016 and beyond. For regulated utilities in Alberta under PBR mechanisms, including FortisAlberta, the impact of the changes to the allowed ROE and common equity component of capital structure resulting from the GCOC Proceeding applies to the portion of rate base that is funded by capital tracker revenue only. For assets not being funded by capital tracker revenue, no revenue adjustment is required for the change in the allowed ROE and common equity component of capital structure, from that set in an earlier GCOC decision.

In April 2015 the AUC initiated a GCOC Proceeding to set the allowed ROE and capital structure for 2016 and 2017. While the AUC approved a request by utilities in Alberta to negotiate matters at issue in the GCOC Proceeding for 2016, a negotiated settlement was not reached and a 2016 and 2017 GCOC Proceeding commenced. A hearing is scheduled for June 2016 and a decision is expected before the end of 2016.

Capital Tracker Applications

The funding of capital expenditures during the PBR term is a material aspect of the PBR plan for FortisAlberta. The PBR plan provides a capital tracker mechanism to fund the recovery of costs associated with certain qualifying capital expenditures.

In March 2015 the AUC issued its decision related to FortisAlberta's 2013, 2014 and 2015 Capital Tracker Applications. The decision: (i) indicated that the majority of the Company's applied for capital trackers met the established criteria and were, therefore, approved for collection from customers; (ii) approved FortisAlberta's accounting test to determine qualifying K factor amounts; and (iii) confirmed certain inputs to be used in the accounting test, including the conclusion that the weighted average cost of capital be based on actual debt rates and the allowed ROE and capital structure approved in the GCOC Proceeding.

In September 2015 the AUC approved FortisAlberta's compliance filing related to the 2015 Capital Tracker Decision, substantially as filed. Capital tracker revenue of \$17 million was approved for 2013 on an actual basis and capital tracker revenue of \$42 million and \$62 million was approved on a forecast basis for 2014 and 2015, respectively. FortisAlberta collected \$15 million, \$29 million and \$62 million in 2013, 2014 and 2015, respectively, related to capital tracker expenditures.

In May 2015 FortisAlberta filed an application with the AUC seeking: (i) capital tracker revenue of \$72 million for 2016 and \$90 million for 2017; (ii) a reduction of \$5 million to the 2014 capital tracker revenue to reflect actual capital expenditures; and (iii) approval of additional revenue related to capital tracker amounts that had not been fully approved in the 2015 Capital Tracker Decision. A hearing related to this proceeding concluded in October 2015, with a decision from the regulator expected in the first quarter of 2016.

FortisAlberta recognized capital tracker revenue of approximately \$59 million in 2015, of which \$9 million was related to updates to the 2013 and 2014 capital tracker approved amounts. The capital tracker revenue for 2015 of approximately \$50 million incorporates an update for related 2015 capital expenditures as compared to the approved forecast reflected in current rates. This resulted in a deferral of \$12 million of 2015 capital tracker revenue as a regulatory liability.

2016 Annual Rates Application

In December 2015 the regulator approved FortisAlberta's 2016 Annual Rates Application substantially as filed. The rates and riders, effective January 1, 2016, include an increase of approximately 4.6% to the distribution component of customer rates. This increase reflects: (i) a combined inflation and productivity factor of 0.9%; (ii) a K factor placeholder of \$64 million, which is 90% of the depreciation and return associated with the 2016 forecast capital tracker expenditures as filed in the capital tracker applications, as discussed previously; and (iii) \$17 million for adjustments to 2013, 2014 and 2015 capital tracker revenue as filed in the capital tracker compliance filing related to the 2015 capital tracker decision.

Utility Asset Disposition Matters

In previous decisions, the AUC made statements regarding cost responsibility for stranded assets and gains or losses related to extraordinary retirement of utility assets, which FortisAlberta and other Alberta utilities challenged as being incorrectly made. Stranded assets are generally understood to be utility assets no longer used to provide utility service as a result of extraordinary circumstances. The AUC's statements implied that the shareholder is responsible for the cost of stranded assets in a broader sense than that generally understood by regulated utilities and also conflicted with the *Electric Utilities Act* (Alberta). As a result, the utilities in Alberta had filed leave to appeal motions with the Court of Appeal of Alberta.

In September 2015 the Court of Appeal of Alberta issued a decision that dismissed the appeals of the utilities. The basis for the decision was that the AUC should be accorded deference for its conclusions in utility asset disposition matters. The decision by the Court of Appeal of Alberta has no immediate impact on FortisAlberta's financial position. However, the Company is exposed to the risk that unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to an extraordinary retirement will not be recoverable from customers. In November 2015 the utilities in Alberta filed a leave to appeal motion with the Supreme Court of Canada, the outcome and timing of which is unknown.

Eastern Canadian Electric Utilities

In October 2015 Newfoundland Power filed a 2016/2017 GRA with the PUB to set customer rates effective July 1, 2016. The Company is proposing an overall average increase in electricity rates of 3.1%. The GRA will include a full review of Newfoundland Power's costs, including cost of capital. The application is currently under review by the PUB. A public hearing is scheduled to begin at the end of the first quarter of 2016 and a decision on the application is expected by the end of the second quarter of 2016.

In October 2015 Maritime Electric filed a GRA with the IRAC to set customer rates effective March 1, 2016, on expiry of the *Prince Edward Island Energy Accord*. In January 2016 Maritime Electric and the Government of PEI entered into a 2016 General Rate Agreement covering the three-year period from March 1, 2016 through February 28, 2019. The agreement, which is subject to regulatory approval, is generally consistent with the GRA filed in October 2015, however, reflects an allowed ROE capped at 9.35% on a maximum average common equity component of capital structure of 40%. Under the agreement, the typical customer electricity cost increase will be limited to a maximum of 2.3% annually.

Significant Regulatory Proceedings

The following table summarizes significant ongoing regulatory proceedings, including filing dates and expected timing of decisions for the Corporation's regulated utilities.

Regulated Utility	Application/Proceeding	Filing Date	Expected Decision
TEP	GRA for 2017	November 2015	Fourth quarter of 2016
UNS Electric	GRA for 2016	May 2015	Third quarter of 2016
Central Hudson	Reforming the Energy Vision	Not applicable	To be determined
FEI	2016 Cost of Capital Application	October 2015	Second quarter of 2016
FortisAlberta	2016/2017 Capital Tracker Application	May 2015	First quarter of 2016
	2016/2017 GCOC Proceeding	Not applicable	Second half of 2016
Newfoundland Power	GRA for 2016/2017	October 2015	Second quarter of 2016

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2015 and December 31, 2014.

Significant Changes in the Consolidated Balance Sheets between December 31, 2015 and December 31, 2014

Balance Sheet Account	Increase/ (Decrease) (\$ millions)	Explanation
Regulatory assets – current and long-term	117	The increase was mainly due to: (i) an increase in regulatory deferred income taxes, mainly at FortisAlberta; (ii) the impact of foreign exchange on the translation of US dollar-denominated regulatory assets; and (iii) the deferral of various other costs as permitted by the regulators. The above-noted increases were partially offset by a reduction in regulatory assets at Central Hudson due to the offsetting of certain regulatory account balances, as approved by the regulator, and a decrease in the deferral for employee future benefits.

Significant Changes in the Consolidated Balance Sheets between December 31, 2015 and December 31, 2014 (cont'd)

Balance Sheet Account	Increase/ (Decrease) (\$ millions)	Explanation
Utility capital assets	2,416	The increase primarily related to utility capital expenditures and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets, partially offset by depreciation and customer contributions.
Non-utility capital assets	(664)	The decrease was due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.
Goodwill	441	The increase was due to the impact of foreign exchange on the translation of US dollar-denominated goodwill.
Short-term borrowings	181	The increase was mainly due to higher short-term borrowings at FortisBC Energy and FortisBC Electric, largely to finance utility capital expenditures.
Regulatory liabilities – current and long-term	193	The increase was mainly due to the impact of foreign exchange on the translation of US dollar-denominated regulatory liabilities and higher rate stabilization accounts at FortisBC Energy, partially offset by a reduction in regulatory liabilities at Central Hudson due to the offsetting of certain regulatory account balances, as approved by the regulator.
Long-term debt (including current portion)	732	The increase was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely in support of energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.
Capital lease and finance obligations (including current portion)	(190)	The decrease was mainly due to the purchase of an additional ownership interest in the Springerville Unit 1 generating facility and the Springerville coal handling facilities at UNS Energy following the expiry of lease arrangements.
Deferred income tax liabilities	424	The increase was primarily due to tax timing differences mainly related to capital expenditures at the regulated utilities and the impact of foreign exchange on the translation of US dollar-denominated deferred income tax liabilities.
Shareholders' equity (before non-controlling interests)	1,189	The increase primarily related to: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans.

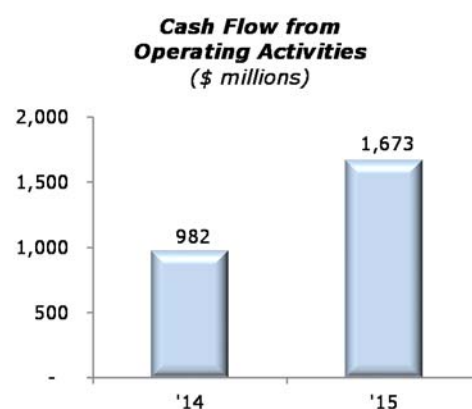
LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CONSOLIDATED CASH FLOWS

The table below outlines the Corporation's sources and uses of cash in 2015 compared to 2014, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows			
Years Ended December 31			
<i>(\$ millions)</i>	2015	2014	Variance
Cash, Beginning of Year	230	72	158
Cash Provided by (Used in):			
Operating Activities	1,673	982	691
Investing Activities	(1,368)	(4,199)	2,831
Financing Activities	(346)	3,361	(3,707)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	53	14	39
Cash, End of Year	242	230	12

Operating Activities: Cash flow from operating activities in 2015 was \$691 million higher than in 2014. The increase was driven by higher cash earnings and favourable changes in working capital. The increase in cash earnings was driven by the acquisition of UNS Energy in August 2014. Earnings contribution from the Waneta Expansion and higher cash earnings at FortisAlberta also contributed to the increase. Favourable changes in working capital at FortisBC Energy and UNS Energy were partially offset by unfavourable changes at FortisAlberta.



Investing Activities: Cash used in investing activities in 2015 was \$2,831 million lower than in 2014. The decrease was due to the acquisition of UNS Energy in August 2014 for a net cash purchase price of \$2,745 million. Also contributing to the decrease were proceeds received from the sale of commercial real estate assets in June 2015 for \$430 million, hotel assets in October 2015 for \$365 million, and generation assets in Upstate New York in June 2015 for \$77 million (US\$63 million), compared to proceeds of \$105 million (US\$95 million) on the sale of Griffith in March 2014. The decrease was partially offset by an increase in capital expenditures of \$518 million, driven by a full year contribution from UNS Energy and higher capital spending at most of the Corporation's regulated utilities, partially offset by lower non-regulated capital expenditures due to the completion of the Waneta Expansion and the sale of commercial real estate and hotel assets.

Financing Activities: Cash provided by financing activities in 2015 was \$3,707 million lower than in 2014. The decrease was primarily due to financing associated with the acquisition of UNS Energy in August 2014 and the repayment of credit facility borrowings in 2015 using proceeds from the sale of commercial real estate and hotel assets. The acquisition of UNS Energy was financed from proceeds of \$1,800 million, or \$1,725 million net of issue costs, from the issue of convertible debentures, proceeds from the issuance of preference shares and credit facility borrowings. In October 2014 substantially all of the convertible debentures were converted into 58.2 million common shares of Fortis.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease and finance obligations, and net (repayments) borrowings under committed credit facilities for 2015 and 2014 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs			
Years Ended December 31			
(\$ millions)	2015	2014	Variance
UNS Energy ⁽¹⁾	591	-	591
Central Hudson ⁽²⁾	25	33	(8)
FortisBC Energy ⁽³⁾	150	-	150
FortisAlberta ⁽⁴⁾	149	274	(125)
FortisBC Electric ⁽⁵⁾	-	198	(198)
Newfoundland Power ⁽⁶⁾	75	-	75
Caribbean Utilities ⁽⁷⁾	-	57	(57)
Fortis Turks and Caicos ⁽⁸⁾	12	92	(80)
Corporate ⁽⁹⁾	-	539	(539)
Total	1,002	1,193	(191)

⁽¹⁾ In February 2015 TEP issued 10-year US\$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures. In April 2015 UNS Electric issued 30-year US\$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes. In August 2015 UNS Electric issued 12-year US\$80 million 3.22% unsecured notes and UNS Gas issued 30-year US\$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt.

⁽²⁾ In March 2015 Central Hudson issued 10-year US\$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes. In March 2014 Central Hudson issued 10-year US\$30 million unsecured notes with a floating interest rate of 3-month LIBOR plus 1%. The net proceeds were used to repay maturing long-term debt and for other general corporate purposes.

⁽³⁾ In April 2015 FortisBC Energy issued 30-year \$150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings and for general corporate purposes.

⁽⁴⁾ In September 2015 FortisAlberta issued 30-year \$150 million 4.27% senior unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes. In September 2014 FortisAlberta issued \$275 million senior unsecured debentures in a dual tranche of 10-year \$150 million at 3.30% and 30-year \$125 million at 4.11%. The net proceeds were used to repay maturing long-term debt, finance capital expenditures and for general corporate purposes.

⁽⁵⁾ In October 2014 FortisBC Electric issued 30-year \$200 million 4.00% senior unsecured debentures. The net proceeds were used to repay long-term debt and credit facility borrowings.

⁽⁶⁾ In September 2015 Newfoundland Power issued 30-year \$75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

⁽⁷⁾ In November 2014 Caribbean Utilities issued a total of US\$50 million unsecured notes with terms to maturity ranging from 15 to 32 years and coupon rates ranging from 3.65% to 4.53%. The net proceeds were used to finance capital expenditures.

⁽⁸⁾ In January 2015 Fortis Turks and Caicos issued 15-year US\$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes. In December 2014 Fortis Turks and Caicos issued 15-year US\$80 million 4.75% unsecured notes. The net proceeds were used to repay inter-company loans with a direct subsidiary of Fortis.

⁽⁹⁾ In June 2014 the Corporation issued US\$213 million unsecured notes with terms to maturity ranging from 5 to 30 years and coupon rates ranging from 2.92% to 4.88%. The weighted average term to maturity was approximately 9 years and the weighted average coupon rate was 3.51%. Net proceeds were used to repay US-dollar denominated borrowings on the Corporation's committed credit facility and for general corporate purposes. In September 2014 the Corporation issued US\$287 million unsecured notes with terms to maturity ranging from 7 to 30 years and coupon rates ranging from 3.64% to 5.03%. The weighted average term to maturity was approximately 12 years and the weighted average coupon rate was 4.11%. Net proceeds were used to repay long-term debt and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations			
Years Ended December 31			
<i>(\$ millions)</i>	2015	2014	Variance
UNS Energy	(449)	-	(449)
Central Hudson	-	(24)	24
FortisBC Energy	(92)	(6)	(86)
FortisAlberta	-	(200)	200
FortisBC Electric	-	(140)	140
Newfoundland Power	(6)	(35)	29
Caribbean Utilities	(17)	(19)	2
Fortis Turks and Caicos	(4)	(4)	-
Fortis Properties	(34)	(22)	(12)
Corporate	-	(293)	293
Total	(602)	(743)	141

Net (Repayments) Borrowings Under Committed Credit Facilities			
Years Ended December 31			
<i>(\$ millions)</i>	2015	2014	Variance
UNS Energy	(199)	61	(260)
FortisAlberta	30	3	27
FortisBC Electric	-	(54)	54
Newfoundland Power	(47)	65	(112)
Corporate	(406)	535	(941)
Total	(622)	610	(1,232)

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.

In September 2014 Fortis issued 24 million First Preference Shares, Series M for gross proceeds of \$600 million. The net proceeds were used to repay a portion of credit facility borrowings used to initially finance a portion of the acquisition of UNS Energy.

Common share dividends paid in 2015 totalled \$232 million, net of \$156 million of dividends reinvested, compared to \$194 million, net of \$81 million of dividends reinvested, paid in 2014. 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 \$1.40 in 2015 compared to \$1.28 in 2014. The weighted average number of common shares outstanding was 278.6 million for 2015 compared to 225.6 million for 2014.

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, 2015, are outlined in the following table.

Contractual Obligations As at December 31, 2015 (\$ millions)	Total	Due					Due after 5 years
		within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	
Long-term debt	11,240	384	71	283	239	857	9,406
Interest obligations on long-term debt	9,435	536	512	507	495	488	6,897
Capital lease and finance obligations ⁽¹⁾	2,478	72	74	93	77	75	2,087
Renewable power purchase obligations ⁽²⁾	1,589	93	93	92	92	92	1,127
Gas purchase obligations ⁽³⁾	1,449	366	253	222	153	131	324
Power purchase obligations ⁽⁴⁾	1,440	281	209	180	102	36	632
Long-term contracts - UNS Energy ⁽⁵⁾	1,057	146	141	105	102	82	481
Capital cost ⁽⁶⁾	488	19	19	19	19	19	393
Operating lease obligations ⁽⁷⁾	181	12	11	11	11	8	128
Renewable energy credit purchase agreements ⁽⁸⁾	162	13	13	13	13	13	97
Purchase of Springerville Common Facilities ⁽⁹⁾	147	-	53	-	-	-	94
Employee future benefits funding contributions	139	49	12	8	9	9	52
Waneta Partnership promissory note	72	-	-	-	-	72	-
Joint-use asset and shared service agreements	53	3	3	3	3	3	38
Other ⁽¹⁰⁾	71	15	12	16	3	-	25
Total	30,001	1,989	1,476	1,552	1,318	1,885	21,781

⁽¹⁾ Includes principal payments, imputed interest and executory costs, mainly related to FortisBC Electric's capital lease obligations.

⁽²⁾ TEP and UNS Electric are party to 20-year long-term renewable PPAs totalling approximately US\$1,148 million as at December 31, 2015, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities that have achieved commercial operation. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. These agreements have various expiry dates through 2035. TEP has entered into additional long-term renewable PPAs to comply with renewable energy standards of the State of Arizona; however, the Company's obligation to purchase power under these agreements does not begin until the facilities are operational. In February 2016 one of the generating facilities achieved commercial operation, increasing estimated future payments of renewable PPAs by US\$58 million, which is not included in the table above.

⁽³⁾ Certain of the Corporation's subsidiaries, mainly FortisBC Energy and Central Hudson, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2015. At Central Hudson, the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2015.

⁽⁴⁾ Power purchase obligations include various power purchase contracts held by certain of the Corporation's subsidiaries, as described below.

FortisBC Energy

In March 2015 FortisBC Energy entered into an Electricity Supply Agreement with BC Hydro for the purchase of electricity supply to the Tilbury Expansion Project, with purchase obligations totalling \$513 million as at December 31, 2015.

FortisBC Electric

Power purchase obligations for FortisBC Electric, totalling \$292 million as at December 31, 2015, mainly include a 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, as approved by the BCUC. The capacity and energy to be purchased under this agreement do not relate to a specific plant.

In addition, in November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement (“WECA”), allowing FortisBC Electric to purchase 234 MW of capacity for 40 years, effective April 2015, as approved 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.

FortisOntario

Power purchase obligations for FortisOntario, totalling \$208 million as at December 31, 2015, primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Quebec Energy Marketing for the supply of electricity and capacity, both expiring in December 2019. 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 provides 100 MW of capacity and provides a minimum of 300 GWh of electricity per contract year.

Maritime Electric

Power purchase obligations for Maritime Electric, totalling \$194 million as at December 31, 2015, primarily include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019 and November 2032, as well as an Energy Purchase Agreement with New Brunswick Power (“NB Power”) expiring in February 2019.

Central Hudson

Central Hudson’s power purchase obligations totalled US\$124 million as at December 31, 2015. In June 2014 Central Hudson entered into a contract to purchase available installed capacity from the Danskammer Generating Facility from October 2014 through August 2018 with approximately US\$76 million in purchase commitments remaining as at December 31, 2015. During 2015, Central Hudson entered into agreements to purchase electricity on a unit-contingent basis at defined prices during peak load periods from June 2015 through August 2016, replacing existing contracts which expired in March 2015.

- (5) UNS Energy has entered into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US\$440 million, US\$261 million and US\$63 million, respectively, as at December 31, 2015. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts. As a result of the restructuring of the ownership of the San Juan generating station in January 2016, a new coal supply agreement came into effect under which TEP’s minimum purchase obligations are US\$137 million, which is not included in the previous table.
- (6) Maritime Electric has entitlement to approximately 4.55% of the output from NB Power’s Point Lepreau nuclear generating station 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.
- (7) Operating lease obligations include certain office, warehouse, natural gas T&D asset, rail car, land easement and rights-of-way, and vehicle and equipment leases.
- (8) UNS Energy is party to renewable energy credit purchase agreements, totalling approximately US\$117 million as at December 31, 2015, to purchase the environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

- (9) UNS Energy has entered into a commitment to exercise its fixed-price purchase provision to purchase an undivided 50% leased interest in the Springerville Common Facilities if the lease is not renewed, for a purchase price of US\$106 million, with one facility to be acquired in 2017 and the remaining two facilities to be acquired in 2021.
- (10) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including Performance Share Unit, Restricted Share Unit and Directors' Deferred Share Unit Plan obligations and asset retirement obligations.

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 electricity and gas 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 \$1.9 billion for 2016. Over the five years 2016 through 2020, the Corporation's consolidated capital expenditure program is expected to be approximately \$9 billion, which has not been included in the Contractual Obligations table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with the U.S. Federal Energy Regulatory Commission ("FERC") for the recovery of the cost of and return on five high-voltage transmission projects totalling US\$1.7 billion, of which CH Energy Group's maximum commitment is US\$182 million. CH Energy Group issued a parental guarantee to assure the payment of maximum commitment of US\$182 million. As at December 31, 2015, no payment obligation is expected under this guarantee.

FortisBC Energy issued commitment letters to customers, totalling \$33 million as at December 31, 2015, to provide Energy Efficiency and Conservation ("EEC") funding under the EEC program approved by the BCUC.

Caribbean Utilities is party to primary and secondary fuel supply contracts 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 2016 is 20 million imperial gallons. Fortis Turks and Caicos 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 \$1,340 million as at December 31, 2015 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 8 to the Corporation's 2015 Audited Consolidated Financial Statements.

CAPITAL STRUCTURE

The Corporation's principal businesses of regulated electric and gas utilities 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 35% common equity, 65% debt and preferred equity, 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 As at December 31	2015		2014	
	(\$ millions)	(%)	(\$ millions)	(%)
Total debt and capital lease and finance obligations (net of cash) ⁽¹⁾	11,950	54.8	11,239	56.4
Preference shares	1,820	8.3	1,820	9.1
Common shareholders' equity	8,060	36.9	6,871	34.5
Total ⁽²⁾	21,830	100.0	19,930	100.0

⁽¹⁾ Includes long-term debt and capital lease and finance obligations, including current portions, and short-term borrowings, net of cash

⁽²⁾ Excludes amounts related to non-controlling interests

Excluding capital lease and finance obligations, the Corporation's capital structure as at December 31, 2015 was 53.7% debt, 8.5% preference shares and 37.8% common shareholders' equity (December 31, 2014 - 54.8% debt, 9.5% preference shares and 35.7% common shareholders' equity).

The improvement in the Corporation's capital structure was due to an increase in common shareholders' equity as a result of: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for the year ended December 31, 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans. The capital structure was also impacted by an increase in total debt due to the impact of foreign exchange on the translation of US-dollar denominated debt and new debt in support of energy infrastructure investment, partially offset by regular scheduled debt repayments and net repayments under committed credit facilities.

CREDIT RATINGS

As at December 31, 2015, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A- / Stable (long-term corporate and unsecured debt credit rating)
DBRS	A (low) / Stable (unsecured debt credit rating)

The above-noted credit ratings reflect the Corporation's low 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 reasonable levels of debt at the holding company level. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P affirmed the Corporation's long-term corporate credit rating at A-, revised its unsecured debt credit rating to BBB+ from A-, and revised its outlook on the Corporation to negative from stable. Similarly, in February 2016 DBRS placed the Corporation's credit rating under review with negative implications.

CAPITAL EXPENDITURE PROGRAM

Capital investment in energy infrastructure is required to ensure continued and enhanced performance, reliability and safety of the electricity and gas 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 \$276 million in maintenance and repairs was expensed in 2015 compared to approximately \$203 million in 2014. The increase was largely due to a full year of expense for UNS Energy in 2015.

Gross consolidated capital expenditures for 2015 were approximately \$2.2 billion. A breakdown of these capital expenditures by segment and asset category for 2015 is provided in the following table.

Gross Consolidated Capital Expenditures ⁽¹⁾											
Year Ended December 31, 2015											
<i>(\$ millions)</i>											
	Regulated Utilities							Total Regulated Utilities	Non-Regulated		Total
	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric		Fortis Generation	Non- Utility ⁽²⁾	
Generation	321	1	-	-	3	9	107	441	38	-	479
Transmission	131	37	57	-	19	23	2	269	-	-	269
Distribution	135	102	134	358	38	121	16	904	-	-	904
Facilities, equipment, vehicles and other ⁽³⁾	39	27	254	73	35	14	9	451	-	28	479
Information technology	43	14	15	21	8	8	3	112	-	-	112
Total	669	181	460	452	103	175	137	2,177	38	28	2,243

⁽¹⁾ Represents cash payments to 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 AFUDC.

⁽²⁾ Includes capital expenditures of approximately \$14 million at FAES, which is reported in the Corporate and Other segment

⁽³⁾ Includes capital expenditures associated with the Tilbury Expansion at FortisBC Energy and Alberta Electric System Operator ("AESO") transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast. Gross consolidated capital expenditures of \$2,243 million for 2015 were \$91 million higher than \$2,152 million forecast for 2015, as disclosed in the MD&A for the year ended December 31, 2014. The increase was driven by higher capital spending at FortisBC Energy primarily due to the timing of payments associated with the Tilbury Expansion and at FortisAlberta primarily due to the purchase of two Rural Electrification Associations ("REAs") for approximately \$21 million in 2015, and due to the impact of foreign exchange associated with the translation of US dollar-denominated capital expenditures. The increase was partially offset by lower-than-forecast capital spending at the Waneta Expansion, due to the timing of payments, and at FAES.

Gross consolidated capital expenditures for 2016 are expected to be approximately \$1.9 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2016 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures ⁽¹⁾											
Year Ending December 31, 2016											
<i>(\$ millions)</i>											
	Regulated Utilities							Total Regulated Utilities	Non-Regulated		Total
	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric		Fortis Generation	Non-Utility ⁽²⁾	
Generation	162	2	-	-	2	24	73	263	15	-	278
Transmission	66	30	84	-	21	19	6	226	-	-	226
Distribution	168	142	129	311	29	110	23	912	-	-	912
Facilities, equipment, vehicles and other ⁽³⁾	40	25	118	109	16	9	20	337	-	3	340
Information technology	49	29	18	21	11	12	5	145	-	-	145
Total	485	228	349	441	79	174	127	1,883	15	3	1,901

⁽¹⁾ Represents forecast cash payments to construct 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. Forecast capital expenditures for 2016 are based on a forecast exchange rate of US\$1.00=CAD\$1.38.

⁽²⁾ Includes forecast capital expenditures of approximately \$3 million at FAES, which is reported in the Corporate and Other segment

⁽³⁾ Includes forecast capital expenditures associated with the Tilbury Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

The percentage breakdown of 2015 actual and 2016 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows.

Gross Consolidated Capital Expenditures	Actual	Forecast
Year Ending December 31	2015	2016
<i>(%)</i>		
Growth ⁽¹⁾	40	36
Sustaining ⁽²⁾	44	48
Other ⁽³⁾	16	16
Total	100	100

⁽¹⁾ Includes capital expenditures associated with the Tilbury Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

⁽²⁾ Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

⁽³⁾ Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period 2016 through 2020, excluding the pending acquisition of ITC, gross consolidated capital expenditures are expected to be approximately \$9 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 40% at Regulated Electric & Gas Utilities in the United States; 37% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 17% at Canadian Regulated Gas Utility; 5% at Caribbean Regulated Electric Utilities; and the remaining 1% 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: 35% to meet customer growth; 50% to ensure continued and enhanced performance, reliability and safety of generation and T&D assets, i.e., sustaining capital expenditures; and 15% for facilities, equipment, vehicles, information technology and other assets.

Actual 2015 and forecast 2016 midyear rate base for the Corporation's regulated utilities and the Waneta Expansion is provided in the following table.

Midyear Rate Base (\$ billions)	Actual	Forecast
	2015	2016
UNS Energy ⁽¹⁾	4.1	4.8
Central Hudson ⁽¹⁾	1.4	1.6
FortisBC Energy	3.7	3.7
FortisAlberta	2.7	3.0
FortisBC Electric	1.3	1.3
Eastern Canadian Electric Utilities	1.6	1.7
Regulated Electric Utilities - Caribbean ⁽¹⁾	0.8	0.9
Waneta Expansion	0.8	0.8
Total	16.4	17.8

⁽¹⁾ Actual midyear rate base for 2015 is based on the actual average exchange rate of US\$1.00=CAD\$1.28 and forecast midyear rate base for 2016 is based on a forecast exchange rate of US\$1.00=CAD\$1.38.

The most significant capital projects that are included in the Corporation's base consolidated capital expenditures for 2015 and 2016 are summarized in the table below.

Significant Capital Projects ⁽¹⁾		Pre-2015	Actual 2015	Forecast 2016	Forecast 2017-2020	Expected Year of Completion
Company	Nature of Project					
UNS Energy ⁽²⁾	Interest in Springerville Unit 1	23	57	-	-	2015
	Springerville Coal Handling Facilities Lease Buyout	-	91	-	-	2015
	Pinal Transmission Project	9	84	-	-	2015
	Residential Solar Program	-	1	22	90	Ongoing
Central Hudson ⁽²⁾	Gas Main Replacement Program	7	19	29	135	Post-2020
FortisBC Energy	Tilbury LNG Facility Expansion ⁽³⁾	145	181	105	15	2016
	Lower Mainland System Upgrade	4	11	50	362	2018
FortisAlberta	Pole-Management Program	159	41	42	94	Post-2020
Caribbean Utilities ⁽²⁾	Generation Expansion	12	61	35	-	2016
Waneta Partnership	Waneta Expansion ⁽⁴⁾	679	36	13	97	2015

⁽¹⁾ Represents utility capital asset and intangible asset expenditures, including both the capitalized interest and equity components of AFUDC, where applicable

⁽²⁾ Forecast capital expenditures are based on a forecast exchange rate of US\$1.00=CAD\$1.38 for 2016 through 2020

⁽³⁾ Total project investment as at December 31, 2014 and 2015 includes approximately \$43 million and \$11 million, respectively, in non-cash capital accruals

⁽⁴⁾ 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

UNS Energy completed three significant capital investments in 2015. In January 2015, upon expiration of the Springerville Unit 1 lease, UNS Energy purchased an additional ownership interest in Springerville Unit 1 for US\$46 million. This purchase increased the ownership interest to 49.5%. Additionally, upon expiration of the Springerville Coal Handling Facilities lease in April 2015, UNS Energy purchased an ownership interest in the coal-handling assets for US\$72 million. The Pinal Transmission Project at UNS Energy was also completed in 2015 at a total project cost of US\$79 million. The project consisted of the construction of a 500-kilovolt transmission line in Pinal County that will increase the Company's import capacity from Gila River Unit 3 and the Palo Verde trading hub.

The Residential Solar Program at UNS Energy is a partnership with local solar companies for UNS Energy to own and install rooftop solar systems for residential customers. The total capital cost of the program through 2020 is expected to be approximately US\$82 million, with approximately US\$16 million expected to be spent in 2016.

The Gas Main Replacement Program at Central Hudson is a 15-year replacement program to eliminate and replace leakage-prone pipes throughout the gas distribution system. The proposed replacement program increases the rate of annual expenditures on pipe replacements to approximately US\$20 million to expedite the replacement plan. Approximately US\$15 million was spent on this program in 2015 and an additional US\$21 million is expected to be spent in 2016. The majority of spending is expected post 2020.

FortisBC Energy's ongoing Tilbury LNG Facility Expansion, at an estimated total project cost of \$440 million, will include a second LNG tank and a new liquefier, both to be in service around the end of 2016. FortisBC Energy received an Order in Council from the Government of British Columbia exempting the Tilbury LNG Facility project from further regulatory review. Key construction activities in 2015 were focused on construction of the storage tank and liquefaction process areas. Total projects costs to the end of 2015 were approximately \$326 million.

The Lower Mainland System Upgrade project at FortisBC Energy is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia. The project will be completed in two phases: (i) the Lower Mainland Intermediate Pressure System Upgrade project phase, which is focused on addressing pipeline condition issues; and (ii) the Coastal Transmission System phase, which is intended to increase security of supply by reducing the number of single points of failure. The project has an estimated capital cost of \$427 million, with approximately \$50 million forecast to be spent in 2016, and is expected to be completed in 2018. The BCUC approved the application to replace certain sections of intermediate pressure pipeline segments within the Greater Vancouver area in October 2015. The Coastal Transmission System phase was approved by a Special Direction by the Government of British Columbia in 2014 and will not be subject to further regulatory review.

During 2015 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program to extend the service life of existing poles and to replace poles when deterioration is beyond repair. The total capital cost of the program through 2020 is expected to be approximately \$336 million. Approximately \$41 million was spent on this program in 2015, for a total of \$200 million spent to date.

Caribbean Utilities was the successful bidder for new generation capacity and entered into a design-build contract agreement to cover the purchase and turnkey installation of two 18.5 MW diesel-generating units, one 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment. Approximately US\$48 million was spent on the project in 2015, with approximately US\$25 million forecast to be spent in 2016. The project cost is estimated to be US\$85 million and the plant is expected to be commissioned in mid-2016.

Construction of the \$900 million, 335-MW Waneta Expansion was completed on April 1, 2015, ahead of schedule and on budget. Construction of the Waneta Expansion, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, commenced late in 2010. The expansion added a second powerhouse, immediately downstream of the Waneta Dam on the Pend d'Oreille River, that shares the existing hydraulic head and generates clean, renewable, cost-effective power from water that would otherwise be spilled. The project also included construction of a 10-kilometre, 230-kilovolt transmission line. On April 2, 2015, the Waneta Expansion began generating power, all of which is being sold to BC Hydro and FortisBC Electric under 40-year contracts. Fortis owns a 51% interest in the Waneta Partnership and operates and maintains the non-regulated investment. The capital cost of the Waneta Expansion, as reported in the Significant Capital Projects table, includes capitalized interest by Fortis during construction, 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.

ADDITIONAL INVESTMENT OPPORTUNITIES

In addition to the Corporation's base consolidated capital expenditure forecast, management is pursuing additional investment opportunities within existing service territories. These additional investment opportunities, as discussed below, are not included in the Corporation's base capital expenditure forecast and also exclude the acquisition of ITC.

FortisBC Energy is pursuing additional LNG infrastructure investment opportunities, including a pipeline expansion to the proposed Woodfibre LNG site in Squamish, British Columbia and a further expansion of Tilbury. In December 2014 FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting these projects from further regulatory approval by the BCUC.

The pipeline expansion is conditional on Woodfibre LNG proceeding with its LNG export facility. The Woodfibre LNG plant has passed the British Columbia Environmental Assessment Office review and the Squamish First Nation approved an environmental certificate for the project in October 2015. These approvals are significant milestones; however, the project is pending a Federal Environmental Assessment. In addition, FortisBC Energy's pipeline expansion, at an estimated total project cost of up to \$600 million, is also subject to various environmental approvals. A final investment decision by Woodfibre LNG is expected in 2016.

A further expansion of Tilbury is conditional upon having long-term contracts in place for the offtake of 70% of the additional liquefaction capacity, on average, for the first 15 years of operation. FortisBC Energy has a conditional agreement with Hawaiian Electric Company that would meet this requirement, subject to the regulatory approval process in Hawaii. The Corporation continues to have discussions with Hawaiian Electric Company, which is expected to be the primary offtaker, regarding the viability and scope of the project. Any resulting agreement would be subject to the approval of the Hawaii Public Utilities Commission.

The Corporation also has other significant opportunities that have not yet been included in the Corporation's capital expenditure forecast including, but not limited to, the New York Transco, LLC at Central Hudson to address transmission constraints in New York; renewable energy alternatives at UNS Energy; Wataynikaneyap transmission line to connect remote First Nations communities at FortisOntario; further gas infrastructure opportunities at FortisBC Energy; and consolidation of Rural Electrification Associations at FortisAlberta.

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. For a discussion of the Corporation's cash flow requirements associated with the pending acquisition of ITC, refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" and "Subsequent Event" sections of this MD&A.

In April 2015 FortisBC Energy filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to \$1 billion during the 25-month life of the shelf prospectus. In April 2015 FortisBC Energy issued 30-year \$150 million 3.38% unsecured debentures under the base shelf prospectus.

In June 2015 Fortis injected US\$180 million of equity into TEP. Proceeds were used to repay credit facility borrowings in June 2015 and the balance was used to redeem bonds in August 2015 and provide additional liquidity to TEP. This equity injection fulfilled one of the commitments made by Fortis in order to receive regulatory approval for the acquisition of UNS Energy, and increased TEP's common equity component of capital structure to almost 50%, which is comparable with other regulated utilities in Arizona.

In May 2015 Caribbean Utilities completed a rights offering in which it raised gross proceeds of US\$32 million through the issue of 2.9 million common shares. Fortis invested US\$23 million in approximately 2.2 million common shares of Caribbean Utilities. The net proceeds from the rights offering were used by Caribbean Utilities to finance capital expenditures.

In October 2015 FortisAlberta filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to \$500 million during the 25-month life of the shelf prospectus.

As at December 31, 2015, management expects consolidated fixed-term debt maturities and repayments to be \$313 million in 2016 and to average approximately \$260 million annually over the next five years. 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. 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.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2015 and are expected to remain compliant in 2016.

CREDIT FACILITIES

As at December 31, 2015, the Corporation and its subsidiaries had consolidated credit facilities of approximately \$3.6 billion, of which approximately \$2.4 billion was unused, including \$570 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, as well as large banks in the United States, with no one bank holding more than 20% of these facilities. Approximately \$3.3 billion of the total credit facilities are committed facilities with maturities ranging from 2016 through 2020.

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

Credit Facilities (\$ millions)	Regulated Utilities	Corporate and Other	Total as at December 31, 2015	Total as at December 31, 2014
Total credit facilities ⁽¹⁾	2,211	1,354	3,565	3,854
Credit facilities utilized:				
Short-term borrowings	(511)	-	(511)	(330)
Long-term debt (including current portion) ⁽²⁾	(71)	(480)	(551)	(1,096)
Letters of credit outstanding	(68)	(36)	(104)	(192)
Credit facilities unused	1,561	838	2,399	2,236

⁽¹⁾ Total credit facilities exclude a \$300 million option to increase the Corporation's committed corporate credit facility, as discussed below.

⁽²⁾ As at December 31, 2015, credit facility borrowings classified as long-term debt included \$71 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2014 - \$257 million).

As at December 31, 2015 and 2014, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

The UNS Utilities have a total of US\$350 million (\$484 million) in unsecured committed revolving credit facilities maturing in October 2020, with the option of two one-year extensions.

Central Hudson has a US\$200 million (\$277 million) unsecured committed revolving credit facility, maturing in October 2020, that is utilized to finance capital expenditures and for general corporate purposes. Central Hudson also has an uncommitted credit facility totalling US\$25 million (\$34 million).

FEI has a \$700 million unsecured committed revolving credit facility, maturing in August 2018, that is utilized to finance working capital requirements, capital expenditures and for general corporate purposes.

FortisAlberta has a \$250 million unsecured committed revolving credit facility, maturing in August 2020, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a \$150 million unsecured committed revolving credit facility, maturing in May 2018. 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 a \$100 million unsecured committed revolving credit facility, maturing in August 2019, and a \$20 million demand credit facility. Maritime Electric has a \$50 million unsecured committed revolving credit facility, maturing in February 2019, and a \$5 million unsecured demand credit facility. FortisOntario has a \$30 million unsecured committed revolving credit facility, maturing in June 2016.

Caribbean Utilities has unsecured credit facilities totalling approximately US\$47 million (\$65 million). Fortis Turks and Caicos has short-term unsecured demand credit facilities of US\$26 million (\$36 million), maturing in September 2016.

Corporate and Other

Fortis has a \$1 billion unsecured committed revolving credit facility, maturing in July 2020, that is available for general corporate purposes. The Corporation has the ability to increase this facility to \$1.3 billion. As at December 31, 2015, the Corporation has not yet exercised its option for the additional \$300 million. The Corporation also has a \$35 million letter of credit facility, maturing in January 2017.

UNS Energy Corporation has a US\$150 million (\$208 million) unsecured committed revolving credit facility, maturing in October 2020, with the option of two one-year extensions.

CH Energy Group has a US\$50 million (\$69 million) unsecured committed revolving credit facility, maturing in July 2020, that can be utilized for general corporate purposes.

FHI has a \$30 million unsecured committed revolving credit facility, maturing in April 2018, that is available for general corporate purposes.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of \$104 million as at December 31, 2015 (December 31, 2014 - \$192 million), the Corporation had no off-balance sheet arrangements 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. Regulated utility assets comprised approximately 96% of total assets of Fortis as at December 31, 2015 (December 31, 2014 – 93%). Approximately 96% of the Corporation's operating revenue¹ was derived from regulated utility operations in 2015 (2014 – 95%), and approximately 92% of the Corporation's operating earnings¹, excluding the gains on sale of non-core assets, were derived from regulated utility operations in 2015 (2014 – 91%). The Corporation operates nine utilities in different jurisdictions in Canada, the United States and the Caribbean, with no more than one-third of total assets located in any one regulatory jurisdiction.

Each of the Corporation's regulated utilities is subject to normal regulation that can affect future revenue and earnings. As a result, the utilities are subject to uncertainties faced by regulated entities, including approval by the respective regulatory authorities of electricity and gas 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 processes. When 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 cost of service and earn its allowed ROE, however, a utility is exposed to risks that inflationary increases may exceed the inflationary factor set by the regulator and that the utility may be unable to achieve productivity improvements. In the case of FortisAlberta's current PBR mechanism, there is a risk that capital expenditures may not qualify, or be approved, as a capital tracker where necessary.

Regulators approve the allowed ROEs and deemed capital structures of the utilities. 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.

Electricity and gas 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.

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.

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.

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.

Risks Associated with the Pending Acquisition of ITC: ITC is a public company and its directors have fiduciary duties which may require them to consider competing offers to purchase the common stock of ITC as an alternative to the Acquisition. The agreement and plan of merger preserves the ability of the directors of ITC to accept a competing offer, in certain circumstances. Fortis may exercise its right to match such offer and, as a result, the purchase price could increase and other key transaction terms could change.

The closing of the acquisition of ITC, which is expected to occur in late 2016, is subject to normal commercial risks that the Acquisition will not close on the terms negotiated, or at all. Completion of the Acquisition remains subject to receipt of ITC and Fortis shareholder approvals, certain regulatory, state and federal approvals, and the satisfaction or waiver of other customary closing conditions contained in the agreement and plan of merger. The failure to obtain the required approvals or to satisfy or waive the conditions to closing may result in the termination of the agreement and plan of merger. Fortis intends to complete the Acquisition as soon as practicable after obtaining the required shareholder, regulatory and governmental approvals, and satisfying the other required closing conditions. 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 business, financial condition or results of operations. If the closing of the acquisition of ITC does not take place as contemplated, the Corporation could suffer material adverse consequences. Failure to complete the Acquisition would, in certain circumstances, result in the Corporation being required to pay a termination fee of up to US\$280 million and other potential costs.

Fortis expects that the Acquisition will provide benefits to the Corporation, including approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. There is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation. Failure to realize the anticipated benefits of the acquisition of ITC 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 at rates consistent with the Corporation’s dividend guidance, at current rates or at all.

Financing of the cash portion of the Acquisition is expected to be achieved primarily through the issuance of approximately US\$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. There can be no assurance that such financing sources will be available to Fortis at the desired time or at all, or on cost-efficient or commercially acceptable terms. As a result, there is no certainty that Fortis will reach a binding agreement with minority investors to complete the minority investment prior to closing of the Acquisition or at all. The Acquisition is not conditional upon Fortis securing one or more minority investors. Consummation of the Acquisition without completion of the contemplated minority investment could increase the consolidated indebtedness of the Corporation or result in the requirement for additional common

equity and may have a negative impact on the Corporation's credit ratings and outlook and could result in additional financing costs and the failure to realize some, or all, of the expected benefits of the acquisition, including the extent to which the Acquisition is accretive. The Corporation obtained commitments for an aggregate of US\$3.7 billion non-revolving term credit facilities. The commitments of the lenders to enter into these credit facilities is subject to certain customary 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.

While Fortis intends to become a U.S. Securities and Exchange Commission ("SEC") registrant and list its common shares on the New York Stock Exchange, there is no guarantee that it will be successful in this regard. If the Corporation is successful in this regard, it will be subject to increased regulatory compliance and may be subject to a greater risk of litigation.

The operations of ITC 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. In particular, any decrease in the value of the US dollar relative to the Canadian dollar following the Acquisition could negatively impact the Corporation's net income as reported in Canadian dollars. Fortis may enter into forward foreign exchange contracts and utilize certain other derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past. There is no guarantee that such hedging strategies, if adopted, will be effective.

Fortis expects to incur a variety of costs in 2016 associated with completing the Acquisition. The majority of these costs will be non-recurring expenses related to financing and obtaining shareholder and regulatory approvals. Certain of these costs have already been incurred and other such costs will be incurred even if the Acquisition is ultimately not completed. Additional unanticipated acquisition-related costs may also be incurred in 2016.

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 automatic adjustment mechanisms 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 as a factor for setting allowed ROEs. Uncertainty exists regarding the duration of the current environment of low interest rates and the effect it may have on allowed ROEs of the Corporation's regulated utilities. If interest rates continue to remain at historically low levels, allowed ROEs could decrease. The continuation of a low interest rate environment could adversely affect the Corporation's ability to earn a reasonable ROE, which could have a negative effect on 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 may also be exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and refinancing of long-term debt. Central Hudson, FortisBC Energy and FortisBC Electric, however, have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate credit facilities for recovery from, or refund to, customers in future rates. There can be no assurance that such deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions. UNS Energy and Central Hudson use interest rate swaps and interest rate caps on variable-rate long-term debt to reduce risk associated with interest rates, as permitted by the regulators. 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, almost 90% of the Corporation's consolidated long-term debt as at December 31, 2015 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, 2015.

Total Debt		
As at December 31, 2015	<i>(\$ millions)</i>	<i>(%)</i>
Short-term borrowings	511	4.4
Utilized variable-rate credit facilities classified as long term	551	4.7
Variable-rate long-term debt (including current portion)	333	2.8
Fixed-rate long-term debt (including current portion)	10,284	88.1
Total	11,679	100.0

In 2015 the Corporation's regulated subsidiaries issued approximately \$1 billion in long-term debt, all of which was at fixed interest rates ranging from 2.98% to 4.75%, with terms ranging from 10 to 30 years. The terms negotiated on new long-term debt demonstrate the ability of the Corporation and its 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, 2015, is provided in the "Financial Instruments" section of this MD&A.

Operating and Maintenance Risks: Storms and severe weather conditions, 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. UNS Energy, Central Hudson and FortisBC Energy are exposed to various operational risks, associated with natural gas, 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 operation of UNS Energy's electric generating stations involves certain risks, including equipment breakdown or failure, interruption of fuel supply and lower-than-expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of the generation business. There can be no assurance that the generation facilities of UNS Energy will continue to operate in accordance with expectations.

The operation of electricity T&D assets is also subject to 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. UNS Energy, FortisBC Energy, 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 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 electricity and gas 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 electricity and natural gas 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 electricity and gas, which could have a material adverse effect on the operations of the utilities.

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. Declines in energy sales could adversely impact the respective utilities' results of operations, net earnings and cash flows.

The business of UNS Energy is concentrated in the State of Arizona. In recent years economic conditions in Arizona have contributed significantly to a reduction in retail customer growth and lower energy usage by the Company's residential, commercial and industrial customers. While it is expected that economic conditions in Arizona will improve in the future, if they do not or if they should worsen, retail customer growth rates may stagnate or decline and customers' energy usage may further decline.

FortisBC Energy is 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.

Alberta's economy is impacted by a number of factors, including the level of oil and gas activity in the province, which is influenced by the market prices of oil and gas. A general and extended decline in economic conditions in Alberta or in other jurisdictions where the Corporation's utilities operate would be expected to have the effect of reducing demand for electricity over time. The regulated nature of utility operations, including various mitigating measures approved by certain regulators, helps reduce the impact that lower energy demand associated with poor economic conditions may have on the utilities' earnings. Significantly reduced electricity demand in the Corporation's service areas could materially reduce capital spending forecasts, and specifically capital spending related to new customer growth. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth. A severe and prolonged downturn in economic conditions could have a material adverse effect on the Corporation's results of operations, net earnings and cash flows despite regulatory measures, where applicable, 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 electricity and gas they consume, thereby affecting the aging and collection of the utilities' trade receivables.

The Corporation's service territory in the Caribbean region has been impacted by challenging economic conditions over the past number of years. 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. Assets of Caribbean Regulated Electric Utilities comprise approximately 4% of the Corporation's total assets as at December 31, 2015.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it and/or one of its larger subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions 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 fixed-term debt maturities in 2016 are expected to total \$313 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.

The cost of renewed and extended credit facilities could increase going forward. Due to their regulated nature, any forecast changes in the cost of borrowing at the utilities are eligible to be reflected in customer rates.

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.

In 2015 the following changes were made to debt credit ratings of the Corporation's utilities: (i) in February 2015 Moody's Investor Service ("Moody's") upgraded the debt credit ratings of UNS Energy to 'Baa1' from 'Baa2' and TEP, UNS Electric and UNS Gas to 'A3' from 'Baa1', and (ii) in July 2015 Fitch Ratings ("Fitch") downgraded Central Hudson's debt credit rating to 'A-' from 'A' and changed the rating outlook to stable from negative. Central Hudson's debt continues to be rated 'A' by S&P and 'A2' by Moody's, both with stable outlooks. In December 2015 DBRS confirmed FortisAlberta's debt credit rating of A(low) but revised its outlook to stable from positive. Also, in August 2015 Fitch confirmed TEP's credit rating of BBB+ but revised its outlook to positive from stable and in February 2016 Fitch withdrew its rating on TEP for commercial reasons at TEP's request. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P revised its outlook on TEP, Central Hudson, FortisAlberta, Maritime Electric and Caribbean Utilities to negative from stable. For details on the Corporation's credit ratings, see the "Credit Ratings" section of this MD&A.

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.

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. For details related to environmental issues, refer to the "Business Risk Management – Environmental Risks" section of this MD&A.

Information Technology and Cyber-Security Risks: As operators of critical energy infrastructure, the Corporation's utilities may face a heightened risk of cyber attacks. Information technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business and customer information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

The Corporation's subsidiaries have security measures, policies and controls designed to protect and secure the integrity of its information technology systems, and safeguard the confidentiality of corporate and customer information; however, cyber-security threats frequently change and require ongoing monitoring and detection capabilities. In the event the Corporation's utilities' information technology systems are breached, it could experience service disruptions, property damage, corruption or unavailability of critical data or confidential employee or customer information. If the breach is material in nature, it could adversely affect the financial performance of the Corporation, its reputation and standing with customers and regulators and expose it to claims of third-party damage. All of these factors could adversely affect the Corporation if not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies or, in the case of regulated utilities, through regulatory recovery.

Weather and Seasonality Risk: Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and could materially impact the operations, financial condition and results of operations of the electric utilities. In Canada, Arizona and New York State, cool summers may reduce air conditioning demand, while less severe winters may reduce electric heating load.

At FortisBC Energy and the gas operations of UNS Energy and Central Hudson, weather has a significant impact on gas distribution volumes 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 associated with regulated gas utilities are highest in the first and fourth quarters.

Regulatory deferral mechanisms are in place at certain of the Corporation's regulated utilities, including Central Hudson, FortisBC Energy, FortisBC Electric 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.

Natural gas and coal-fired generating plants require continuous water flow for their operation. Shifts in weather or climate patterns, seasonal precipitation, the timing and rate of melting, run off, and other factors beyond the control of the Corporation, may reduce the water flow to UNS Energy's generation facilities. Any material reduction in the water flow to UNS Energy's generation facilities would limit the ability of the Company to produce and market electricity from those respective facilities and could have a material adverse effect on the results of operations and financial position of the Corporation. Any change in regulations or the level of regulation respecting the use, treatment and discharge of water, or respecting the licensing of water rights in the jurisdictions where UNS Energy operates could result in a material adverse effect on the results of operations and financial position of the Company.

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. Prolonged adverse weather conditions could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Company's entitlement to capacity and energy under the Canal Plant Agreement.

Despite preparations for severe weather, hurricanes and other natural disasters will always remain a risk to the physical assets of 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. Although physical utility 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.

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. Certain of 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 in Belize 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. Prolonged adverse weather conditions, however, could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Waneta Expansion's entitlement to capacity and energy under the Canal Plan Agreement.

Commodity Price Risk: UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market prices of electricity and natural gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of natural gas. The operation of regulator-approved deferral mechanisms to flow through in customer rates the cost of natural gas, purchased power and coal serves to mitigate the impact on earnings of commodity price volatility. The risks have also been reduced by entering into various price-risk management strategies to reduce exposure to commodity rates, including the use of derivative contracts that effectively fix the price of natural gas, power and electricity purchases. 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, coal and purchased power will continue to exist in the future. Also, a severe and prolonged increase in such costs could materially affect FortisBC Energy, UNS Energy 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.

Foreign Exchange Risk: 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 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 gain or loss on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar.

As at December 31, 2015, the Corporation's corporately issued US\$1,535 million (December 31, 2014 – US\$1,496 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2015, the Corporation had approximately US\$3,137 million (December 31, 2014 – US\$2,762 million) in foreign net investments remaining to be hedged. 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 on the balance sheet in accumulated 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 on the balance sheet in accumulated other comprehensive income.

On an annual basis, it is estimated that a 5 cent, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US\$1.00=CAD\$1.38 as at December 31, 2015 would increase or decrease earnings per common share of Fortis by approximately 4 cents, before considering the impact of the pending acquisition of ITC. 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: UNS Energy, Central Hudson and FortisBC Energy may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The above-noted utilities deal with credit quality institutions in accordance with established credit approval practices. These utilities did not experience any counterparty defaults in 2015 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 a financial guarantee from an entity with an investment-grade credit rating.

Competitiveness of Natural Gas in British Columbia: In FortisBC Energy's service territory, natural gas primarily competes with electricity for space and hot water heating load. 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.

Government policy has also impacted the competitiveness of natural gas in British Columbia. The Government of British Columbia has introduced changes to energy policy, including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels. The Government of British Columbia has yet to 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, FortisBC Energy has 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 FortisBC Energy 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 FortisBC Energy to fully recover COS in rates charged to customers.

Natural Gas, Fuel and Electricity Supply: FortisBC Energy is 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, FortisBC Energy is highly dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of FortisBC Energy 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. British Columbia has significant natural gas resources that are expected to be sufficient to meet incremental demand requirements and to continue to supply existing markets. It is uncertain at this time, however, how the pace and location of infrastructure development to connect production to new and existing markets could impact the Corporation's access to supply at fair market prices.

The UNS Utilities are dependent on third parties to supply fuel, including natural gas and coal. Disruption of fuel supply could impair the ability of the Companies to deliver electricity or gas or generate electricity and could adversely affect operations. In addition, a loss of coal suppliers or the inability to renew existing coal or natural gas contracts at favorable terms could significantly affect the ability to serve customers and adversely affect the financial condition and the results of operations of the UNS Utilities.

Newfoundland Power is dependent on Newfoundland Hydro for approximately 93% of its customers' energy requirements and Maritime Electric is dependent on NB Power for approximately 75% of its customers' energy requirements. The Corporation's utilities in the Caribbean 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.

Newfoundland Power experienced losses of electricity supply from Newfoundland Hydro in January 2013 and January 2014, which disabled it from meeting all of its customers' requirements. The PUB is conducting an inquiry and hearing into these system supply issues and related power interruptions. To the extent it is able, Newfoundland Power intends to participate in these reviews in 2016. As well, the Government of Newfoundland and Labrador engaged consultants to complete an independent review of the current electricity system in the province.

Future changes in energy 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 Newfoundland Power's sales. The recovery of Muskrat Falls development costs are expected to materially increase customer electricity rates.

Power Purchase and Capacity Sale Contracts: FortisBC Electric's indirect customers are 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 extreme cases, could ultimately lead to an inability by FortisBC Electric to fully recover its COS in customer rates.

Additionally, the Corporation's regulated electric utilities periodically enter into various power purchase contracts and resale contracts for excess capacity with third parties. Upon expiry of the contracts, there is a risk that the utilities may not be able to secure extensions of such contracts. If the contracts are not extended, there is a risk of the utilities not being able to obtain alternate supplies of similarly priced electricity or not being able to secure additional capacity resale contracts. The utilities are also exposed to risk in the event of non-performance by counterparties to the various power purchase and resale contracts.

Employee Future Benefit Plan Performance and Funding Requirements: Fortis and the majority of its subsidiaries maintain a combination of defined benefit pension and/or OPEB plans for certain of their employees. Approximately 63% of the Corporation's total employees are members of defined benefit pension plans and approximately 72% of employees are members of OPEB plans.

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

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

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

Jointly Owned and Operated Generating Units: Certain of the generating stations from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities and, therefore, may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have limited or no discretion in managing the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed with environmental compliance requirements which could require significant capital expenditures or the closure of such generating stations. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP. In particular, TEP is subject to disagreement and litigation by third-party owners with respect to the existing agreements for Springerville Unit 1. As a result of these disagreements and pending litigation, the third-party owners have and may continue to refuse to pay some or all of their pro rata share of Springerville Unit 1 costs and expenses. For further details, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Technology Developments and Energy Efficiency: New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to have a significant impact on retail sales, which could negatively impact various utilities' results of operations, net earnings and cash flows. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. Utilities are promoting demand-side management programs designed to help customers reduce their energy usage.

Research and development activities are ongoing for new technologies that produce power, enable more efficient storage of energy, or reduce power consumption. These technologies include renewable energy, customer-owned generation, appliances, battery storage, equipment and control systems. Advances in these, or other technologies, could have a significant impact on retail sales which could negatively impact the results of operations, net earnings and cash flows of utilities.

Environmental Risks: The Corporation's electric and gas utilities are subject to inherent environmental risks, as well as environmental laws and regulations, as discussed below.

Inherent Environmental Risks

The Corporation's electric and gas 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. Inherent 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. 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. Additional risks include environmental reclamation associated with coal mines that supply generating stations in which the Corporation has an ownership interest.

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.

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.

Environmental laws and regulations

The Corporation's electric and gas utilities are subject to numerous federal, state and provincial environmental laws and regulations that may increase its cost of operations or expose it to environmental litigation and liabilities. Existing environmental laws and regulations may be revised or new environmental laws and regulations may be adopted or become applicable to the Corporation's operations. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on the results of operations of the Corporation. The utilities would request that additional costs resulting from environmental laws and regulations be recovered from customers in future rates. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive.

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.

The management of greenhouse gas emissions is a specific environmental concern of the Corporation's regulated utilities in Canada and the United States, primarily due to new and emerging federal, provincial and state greenhouse gas laws, regulations and guidelines. In British Columbia, 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* affect, or may potentially affect, the operations of FortisBC Energy and FortisBC Electric. The utilities continue to assess and monitor the impact that the Government's Energy Plan and the *Clean Energy Act* may have on future operations.

In August 2015 the United States Environmental Protection Agency ("EPA") issued the Clean Power Plan ("CPP") limiting carbon emissions from existing and new fossil fuelled power plants. The CPP establishes state-level carbon emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets carbon emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. The CPP will require a shift in generation from coal to natural gas and renewables and could lead to the early retirement of coal generation in Arizona within the 2022 to 2030 compliance time-frame. UNS Energy is currently in the process of transitioning its generation resource mix, as appropriate, in order to reduce carbon emissions. The Company will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop compliance strategies. UNS Energy is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. The Company cannot predict the ultimate outcome of these matters.

The EPA incorporated the compliance obligations for existing power plants located on Indian nations, including the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a plan or that does not have an EPA or approved state plan. UNS Energy will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at the facilities. The Company has submitted comments on the proposed Federal Plan impacting its facilities, including Four Corners and Navajo stating, among other things, that the EPA should not regulate the greenhouse gases on the Navajo Nation because it is not appropriate or necessary. The reduction of greenhouse gases achieved due to the shutdowns resulting from Regional Haze compliance will be equivalent to those required under the CPP rule. UNS Energy cannot predict the ultimate outcome of these matters.

The Company's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule. In February 2016 the United States Supreme Court granted a stay effectively ordering the EPA to stop CPP implementation efforts until legal challenges to the regulation have been resolved. The ruling introduces uncertainty as to whether and when the states and utilities will have to comply with the CPP. UNS Energy will continue to work with the Arizona Department of Environmental Quality to determine what, if any, actions need to be taken in light of the ruling. UNS Energy anticipates that the ruling will likely delay the requirement to submit a plan or request an extension under the CPP by September 2016.

If any of the coal-fired generation plants, or coal-handling facilities, from which UNS Energy obtains power are closed prior to the end of their useful life in response to recent or future changes in environmental regulation, the Company could be required to recognize a material impairment of its assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any such generating stations may force UNS Energy to incur higher costs for replacement capacity and energy. The Company may not be permitted recovery of these costs in customer rates.

In addition, early closures of certain generating units could require UNS Energy to redeem some or all tax-exempt bonds associated with the respective generating units. As at December 31, 2015, approximately 43% of UNS Energy's generating capacity was fuelled by coal.

Environmental laws and regulations have given rise to environmental liabilities at certain of the Corporation's utilities. TEP is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has an ownership interest and is obligated to pay similar costs at the coal mines that supply these generating stations. As at December 31, 2015, TEP has recognized approximately US\$25 million in mine reclamation obligations, representing the present value of the estimated future liability. While TEP has recorded the portion of its obligations for such reclamation costs that can be determined at this time, the total costs and timing of final reclamation at these sites are unknown and could be substantial. TEP currently recovers final mine reclamation costs through regulator-approved mechanisms as costs are paid to the coal suppliers.

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, 2015, Central Hudson has recognized approximately US\$92 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.

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. With the exception of the mine reclamation costs at TEP and the MGP remediation liabilities at Central Hudson, as noted above, as at December 31, 2015, there were no material environmental liabilities recognized in the Corporation's 2015 Audited Consolidated Financial Statements. 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.

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 any 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 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 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 electric and gas utilities and assets require numerous licences, permits, agreements, orders, approvals and certificates (“Approvals”) from various levels of government, government agencies and third parties. For various reasons, including increased stakeholder participation, the Corporation’s regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required Approvals. If there is a delay in obtaining any required Approvals, or if there is a failure to obtain or maintain any required Approvals or to comply with any applicable law, regulation or condition of an approval, or there is a material change to any required Approval, the operation of the assets and the sale of electricity and gas could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation’s subsidiaries.

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.

Within certain portions of the FortisAlberta’s service territory, REAs have been granted by the AUC the right to provide electric distribution service to their eligible members. Members eligible to receive electric distribution service from an REA are those who meet the specific eligibility criteria defined in the integrated operating agreements between the Company and REA. In general, this eligibility criteria has limited the provision of service to customers whose land is used for agricultural activity or as a rural estate property. This historical arrangement has been challenged by some self-operating REAs that are seeking to expand their services to a broader range of customers within the service area that overlaps that of the Company. FortisAlberta is actively resisting these efforts on the part of these self-operated REAs, as it believes the legislative scheme in Alberta does not support this type of competition between the regulated utility and these small rural electricity cooperatives. There is a risk that the efforts of these self-operating REAs to expand their services to a broader range of customers could increase their ability to serve customers in competition with the Company.

The consequence to FortisAlberta of a municipality purchasing its distribution assets or an REA serving more customers in its service territory would be an erosion of the Company’s rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. A significant 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 in Canada 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.

If the OSC relief does not continue as detailed above, the Corporation and its reporting issuer subsidiaries would then be required to become SEC registrants in order to continue reporting under US GAAP, or adopt IFRS. The IASB has 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 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. In connection with the pending acquisition of ITC, Fortis expects to become a registrant with the SEC. As an SEC registrant, Fortis would be entitled under applicable Canadian laws to continue to prepare its consolidated financial statements in accordance with US GAAP.

Changes in Tax Legislation: The Corporation and its subsidiaries are subject to changes in tax legislation in Canada, the United States and other international jurisdictions.

Canadian Tax Legislation

During 2015 there were elections at the federal level and several provincial jurisdictions in Canada. A change in government can result in the passing of new tax legislation, including a change in rates of taxation. The new federal and provincial budgets are expected to be delivered in early 2016 and any resulting changes could have an impact on the Corporation and its Canadian subsidiaries. Any changes in tax legislation could affect the Corporation's results of operations, cash flows and financial position.

U.S. Tax Legislation

In 2015 the U.S. Congress enacted legislation approving the use of bonus depreciation through to 2019, subject to a phase out schedule reducing allowable rates to 50% in 2015 through 2017, 40% in 2018 and 30% in 2019. While this legislation provides greater certainty for planning purposes and reduces the cash tax burden of the Corporation's subsidiaries in the United States, any changes in this or other tax legislation in the United States could affect the Corporation's results of operations, cash flows and financial position.

International Tax Legislation

Fortis conducts business in certain tax-free jurisdictions, including certain countries in the Caribbean and Belize. Canada requires the governments of certain tax-free jurisdictions to enter a Tax Information Exchange Agreement ("TIEA"), which permits dividends paid from those jurisdictions to be exempt from tax when received in Canada. This legislation allows Fortis to receive a tax-free return of capital from the Caribbean. Certain legislation also provides a mechanism for the repayment of upstream loans that were previously used as a tax-deferred repatriation of earnings. The Corporation has approximately \$79 million of upstream loans from its Caribbean subsidiaries, which are required to be repaid by August 2016. The Corporation expects to repay these loans, as required.

A TIEA has not yet been negotiated between Canada and Belize and there are no indications that Canada will conclude negotiations with the GOB in the near future. Until a TIEA is in place, active business earnings in Belize cannot be repatriated to Canada on a tax-free basis; however, the GOB has signed on to the Convention on Mutual Administrative Assistance in Tax Matter, which excludes Belize as a "non-qualifying country". As a result, the Corporation is not required to accrue tax on its active business income from Belize, whether or not repatriated to Canada.

In October 2015 the Organization for Economic Co-operation and Development ("OECD") released its final reports in connection with its action plan to address Base Erosion and Profit Sharing ("BEPS Action Plan"). The basis of the BEPS Action Plan is to identify and curb aggressive tax planning and practices, as well as monitor the international tax systems. Canada has not yet implemented the recommendations of the OECD report into tax treaties and domestic law; however, if it were to be enacted under Canadian tax legislation the Corporation would be required to assess the impacts and determine whether any changes to existing tax practices are required.

Access to First Nations' Lands: FortisBC Energy 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 FortisBC Energy 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 FortisBC Energy and FortisBC Electric. However, there can be no certainty that the settlement process will not have a material adverse effect on FortisBC Energy 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 FortisBC Energy 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 the Company and, therefore, may have a material adverse effect on FortisAlberta.

Labour Relations Risk: The Corporation's subsidiaries employ 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.

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 and in 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 to ensure the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

CHANGES IN ACCOUNTING POLICIES

The new US GAAP accounting policies that are applicable to, and were adopted by, Fortis, effective during 2015, are described as follows.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
The Corporation prospectively adopted Accounting Standards Update ("ASU") No. 2014-08 that changes the criteria and disclosures for reporting discontinued operations. As a result, the sale of commercial real estate and hotel assets and the sale of non-regulated generation assets in 2015 did not meet the criteria for discontinued operations. The sales are consistent with the Corporation's focus on its core utility business and, therefore, do not represent a strategic shift in operations.

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period

The Corporation early adopted ASU No. 2014-12 that resolves diversity in practice for employee share-based payments with performance targets that can entitle an employee to benefit from an award regardless of if they are rendering services at the date the performance target is achieved. The adoption of this update was applied prospectively and did not have a material impact on the Corporation's 2015 Audited Consolidated Financial Statements.

Simplifying the Presentation of Debt Issuance Costs

The Corporation early adopted ASU No. 2015-03 that requires debt issuance costs to be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The adoption of this update was applied retrospectively and resulted in the reclassification of debt issuance costs of approximately \$65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014. Additionally, the Corporation early adopted ASU No. 2015-15 that clarifies the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements. The update permits an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The adoption of this update was applied retrospectively and did not have a material impact on the Corporation's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes

The Corporation early adopted ASU No. 2015-17 that requires deferred tax assets and liabilities to be classified and presented as long term on the consolidated balance sheet. The adoption of this update was applied retrospectively and resulted in the reclassification of current deferred income taxes assets of \$158 million, long-term deferred income tax assets of \$62 million, and current deferred income tax liabilities of \$9 million to long-term deferred income tax liabilities on the consolidated balance sheet as at December 31, 2014. As a result, the Corporation also reclassified current regulatory assets of \$18 million, current regulatory liabilities of \$19 million, and long-term regulatory liabilities of \$91 million, to long-term regulatory assets on the consolidated balance sheet as at December 31, 2014, all associated with regulatory deferred income taxes.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by FASB, but have not yet been adopted by Fortis. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the IASB to improve financial reporting by creating common revenue recognition guidance for US GAAP and IFRS that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. ASU No. 2015-14 was issued in August 2015 and the amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The majority of the Corporation's revenue is generated from energy sales to customers based on published tariff rates, as approved by the respective regulators, and is expected to be in the scope of ASU No. 2014-09. Fortis has not yet selected a transition method and is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures. The Corporation plans to have this assessment substantially complete by the end of 2016.

Amendments to the Consolidation Analysis

ASU No. 2015-02 was issued in February 2015 and the amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following with regard to limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. The adoption of this update is not expected to materially impact the Corporation's consolidated financial statements, however, it is expected to change the Corporation's 51% controlling ownership interest in Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional note disclosure.

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 Liability as at December 31 (\$ millions)	2015		2014	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	56	59	53	56
Long-term debt, including current portion	11,240	12,614	10,501	12,237

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 following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

Financial Instruments Carried at Fair Value			
As at December 31 (\$ millions)	Fair value hierarchy	2015	2014
Assets			
Energy contracts subject to regulatory deferral ^{(1) (2) (3)}	Levels 2/3	7	3
Energy contracts not subject to regulatory deferral ^{(1) (2)}	Level 3	2	1
Available-for-sale investment ^{(4) (5)}	Level 1	33	-
Assets held for sale	Level 2	9	-
Other investments ⁽⁴⁾	Level 1	12	5
Total gross assets		63	9
Less: Counterparty netting not offset on the balance sheet ⁽⁶⁾		(6)	(3)
Total net assets		57	6
Liabilities			
Energy contracts subject to regulatory deferral ^{(1) (2) (7)}	Levels 1/2/3	78	72
Energy contracts not subject to regulatory deferral ^{(1) (2)}	Level 3	-	1
Energy contracts - cash flow hedges ^{(2) (8)}	Level 3	-	1
Interest rate swaps - cash flow hedges ⁽⁸⁾	Level 2	5	5
Total gross liabilities		83	79
Less: Counterparty netting not offset on the balance sheet ⁽⁶⁾		(6)	(3)
Total net liabilities		77	76

⁽¹⁾ The fair value of the Corporation's energy contracts is recorded in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in rates as permitted by the regulators, with the exception of long-term wholesale trading contracts.

⁽²⁾ Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and those that qualify as cash flow hedges.

⁽³⁾ Includes \$2 million - level 2 and \$5 million - level 3 (2014 - \$3 million - level 3)

⁽⁴⁾ Included in long-term other assets on the consolidated balance sheet

⁽⁵⁾ The cost of the available-for-sale investment was \$35 million and unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

⁽⁶⁾ Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.

⁽⁷⁾ Includes \$1 million - level 1, \$52 million - level 2 and \$25 million - level 3 (2014 - \$2 million - level 1, \$35 million - level 2 and \$35 million - level 3)

⁽⁸⁾ The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments 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.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships and transmission and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds electricity swap contracts and gas swap and option contracts to minimize commodity price volatility for electricity and natural gas purchases by fixing the effective purchase price for the defined commodities. The fair value of the electricity swap contracts and gas swap and option contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas purchase contract premiums 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 cost of natural gas.

As at December 31, 2015, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recorded in earnings. As at December 31, 2015, unrealized losses of \$74 million (December 31, 2014 - \$69 million) were recognized in regulatory assets and unrealized gains of \$3 million were recognized in regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral

In June 2015 UNS Energy entered into long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with the ratepayer through UNS Energy's rate stabilization accounts.

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on lease debt, and held a power purchase swap, that expired in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately \$1 million.

Central Hudson holds interest rate cap contracts expiring in 2016 and 2017 on bonds with a total principal amount of US\$64 million. Variations in the interest costs of the bonds, including any gains or losses associated with the interest rate cap contracts, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator and do not impact earnings.

Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

Volume of Derivative Activity

As at December 31, 2015, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity Contracts		2016	2017	2018	2019	2020	There- after
	(year)	(#)						
Energy contracts subject to regulatory deferral:								
Electricity swap contracts (<i>GWh</i>)	2019	8	1,043	730	438	219	-	-
Electricity power purchase contracts (<i>GWh</i>)	2017	28	1,027	145	-	-	-	-
Gas swap and option contracts (<i>PJ</i>)	2018	154	40	10	4	-	-	-
Gas purchase contract premiums (<i>PJ</i>)	2024	89	91	42	38	22	22	64
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts (<i>GWh</i>)	2016	6	1,310	-	-	-	-	-

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, 2015, Fortis recognized a total of \$2,532 million in regulatory assets (December 31, 2014 - \$2,415 million) and \$1,638 million in regulatory liabilities (December 31, 2014 - \$1,445 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, 2015, the Corporation’s consolidated capital assets and intangible assets were approximately \$20.1 billion, or approximately 70%, of total consolidated assets compared to approximately \$18.3 billion, or approximately 70%, of total consolidated assets as at December 31, 2014. Depreciation and amortization was \$873 million for 2015 compared to \$688 million for 2014.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-asset retirement obligation (“ARO”) removal costs in depreciation, with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs 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, 2015 was \$1,060 million, an increase of \$109 million from \$951 million as at December 31, 2014, mainly due to the impact of foreign exchange associated with the translation of US dollar-denominated non-ARO removal cost liabilities.

Changes in depreciation rates, resulting from a change in the estimated service life or removal costs, could 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, amortization and removal cost rates, as applicable, are approved by the respective regulatory authority. 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.

Effective January 1, 2015, FortisAlberta’s depreciation and amortization rates were changed as a result of a technical update to its last depreciation study, which was completed as of December 31, 2010. A technical update adjusts depreciation and amortization rates based on current capital asset balances, while retaining the depreciation parameters established in the last approved depreciation study. As a result, FortisAlberta’s depreciation and amortization expense were reduced by approximately \$7 million in 2015.

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 2015 or 2014.

As at December 31, 2015, consolidated goodwill totalled approximately \$4.2 billion (December 31, 2014 - \$3.7 billion). Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights and totalled approximately \$106 million as at December 31, 2015 (December 31, 2014 - \$77 million).

Fortis performs an annual internal quantitative assessment for each reporting unit. 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 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 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 external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

In calculating goodwill impairment, Fortis determines those reporting units that will have fair value estimated by an 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 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 2015 or 2014 with respect to goodwill or indefinite-lived intangible assets.

Employee Future Benefits:

Defined Benefit Pension Plans

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 2016, is 6.17%, which is down from 6.25% used for 2015. The decrease in the average long-term rate of return reflects shifting of plan assets from equities to fixed income assets. The defined benefit pension plan assets experienced total positive returns of approximately \$30 million in 2015 compared to expected positive returns of \$140 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, 2015, and to determine net pension cost for 2016, is 4.21%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2014, and to determine net pension cost for 2015, of 4.00%. 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, except as follows for UNS Energy. UNS Energy adopted the spot rate methodology for determining net pension cost for 2016.

There was a \$26 million increase in consolidated defined benefit net pension cost for 2015 compared to 2014, mainly due to the acquisition of UNS Energy in August 2014, and foreign currency translation impacts. Any increases in defined benefit net pension cost at the regulated utilities for 2016 are expected to be recovered from customers in rates, subject to regulatory lag and forecast risk at certain of the utilities.

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 2015 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2015 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate		
Year Ended December 31, 2015		
(Decrease) increase <i>(\$ millions)</i>	Net pension benefit cost	Projected benefit obligation ⁽¹⁾
Impact of increasing the rate of return assumption by 100 basis points	(24)	-
Impact of decreasing the rate of return assumption by 100 basis points	20	(44)
Impact of increasing the discount rate assumption by 100 basis points	(44)	(370)
Impact of decreasing the discount rate assumption by 100 basis points	51	469

⁽¹⁾ At FortisBC Energy and FortisBC Electric, certain defined benefit pension plans have pension indexing provisions which provide for a portion of investment returns to be allocated in order to provide for indexing of pension benefits. 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 FortisBC Energy 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 include the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

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. Central Hudson, FortisBC Energy, 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, 2015, for all defined benefit pension plans, the Corporation had consolidated projected benefit obligations of \$2,828 million (December 31, 2014 - \$2,604 million) and consolidated plan assets of \$2,466 million (December 31, 2014 - \$2,216 million), for a consolidated funded status in a liability position of \$362 million (December 31, 2014 - \$388 million). During 2015, the Corporation recognized consolidated net pension benefit cost of \$97 million (2014 - \$71 million).

OPEB Plans

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 plans at UNS Energy and 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 UNS Energy and Central Hudson experienced no returns in 2015 compared to expected positive returns of approximately \$12 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 2015 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2015 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate		
Year Ended December 31, 2015		
Increase (decrease) <i>(\$ millions)</i>	Net OPEB cost	Accumulated benefit obligation
Impact of increasing the health care cost trend rate assumption by 100 basis points	7	51
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(5)	(43)
Impact of increasing the discount rate assumption by 100 basis points	(6)	(71)
Impact of decreasing the discount rate assumption by 100 basis points	9	85

Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net OPEB cost from forecast net OPEB 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, 2015, for all OPEB plans, the Corporation had consolidated accumulated benefit obligations of \$574 million (December 31, 2014 - \$564 million) and consolidated plan assets of \$181 million (December 31, 2014 - \$154 million), for a consolidated funded status in a liability position of \$393 million (December 31, 2014 - \$410 million). During 2015, the Corporation recognized consolidated net OPEB benefit cost of \$27 million (2014 - \$21 million).

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, 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, 2015 and 2014, with the exception of AROs recognized by UNS Energy, Central Hudson and FortisBC Electric.

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 and interconnection facilities 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, 2015, the Corporation's total AROs were \$49 million (December 31, 2014 - \$37 million). UNS Energy's AROs were primarily associated with TEP's generation and photovoltaic assets; Central Hudson's AROs were primarily associated with asbestos remediation; and FortisBC Electric's AROs were associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from electrical equipment. The total ARO liability as at December 31, 2015 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, 2015, 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. Electricity and gas 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 electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator. Effective July 1, 2015, Central Hudson is permitted by the regulator to accrue unbilled revenue for electricity consumed at each period end for all of its electricity customers. As at December 31, 2014, approximately \$15 million (US\$13 million) in unbilled revenue at Central Hudson, associated with certain electricity customers, was not accrued, as permitted by the regulator.

The unbilled revenue accrual for the period is based on estimated electricity and gas sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the electricity and gas sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of electricity and gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity and gas consumption will result in adjustments of electricity and gas revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2015, the amount of accrued unbilled revenue recognized in accounts receivable was approximately \$404 million (December 31, 2014 - \$365 million) on consolidated revenue of \$6,727 million for 2015 (2014 - \$5,401 million). The increase in accrued unbilled revenue from December 31, 2014 was primarily due to the impact of foreign exchange on the translation of US dollar-denominated unbilled revenue accruals.

Capitalized Overhead: As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, 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.

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 contingencies.

UNS Energy*Springerville Unit 1*

In November 2014 the Springerville Unit 1 third-party owners filed a complaint (“FERC Action”) against TEP with FERC, alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners’ energy from their Springerville Unit 1 interests beginning in January 2015 for the price specified by the third-party owners. In February 2015 FERC issued an order denying the third-party owners’ complaint. In March 2015 the third-party owners filed a request for rehearing in the FERC Action, which FERC denied in October 2015. In December 2015 the third-party owners appealed FERC’s order denying the third-party owners’ complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015 TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

In December 2014 the third-party owners filed a complaint (“New York Action”) against TEP in the Supreme Court of the State of New York, New York County. In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged and the court’s subsequent ruling on the motions, the third-party owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; and that TEP breached the lease transaction documents by refusing to pay certain of the third-party owners’ claimed expenses. The third amended complaint seeks US\$71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The third-party owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015 the third-party owners filed a motion for summary judgment on their claim that TEP failed to pay certain of the third-party owners’ claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent notices to TEP that alleged that TEP had defaulted under the third-party owners’ leases. The notices demanded that TEP pay liquidated damages totalling approximately US\$71 million. In letters to the owner trustees, TEP denied the allegations in the notices.

In April 2015 TEP filed a demand for arbitration with the American Arbitration Association (“AAA”) seeking an award of the owner trustees and co-trustees’ share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015 the third-party owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The third-party owners’ arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the third-party owners’ fees and expenses. TEP and the third-party owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015 the third-party owners filed an amended arbitration demand adding claims that TEP has converted the third-party owners’ water rights and certain emission reduction payments and that TEP is improperly dispatching the third-party owners’ unscheduled Springerville Unit 1 power and capacity.

In October 2015 the arbitration panel granted TEP’s motion for interim relief, ordering the owner trustees and co-trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the third-party owners’ motion for interim relief, which had requested that TEP be enjoined from dispatching the third-party owners’ unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling the third-party owners’ entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 2015. The arbitration hearing is scheduled for July 2016.

In November 2015 TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming owner trustee and co-trustee as respondents. The petition seeks an

order from the court confirming the interim arbitration order under the Federal Arbitration Act. In December 2015 the owner trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As at December 31, 2015, TEP billed the third-party owners approximately US\$23 million for their pro-rata share of Springerville Unit 1 expenses and US\$4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the claims, the Company cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the consolidated financial statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners and to vigorously pursue the claims it has asserted against the third-party owners.

TEP and the third-party owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US\$43 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The mine reclamation liability recorded as at December 31, 2015 was US\$25 million (December 31, 2014 - US\$22 million), and represents the present value of the estimated future liability.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms.

TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset.

Central Hudson

Site Investigation and Remediation Program

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 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, 2015, an obligation of US\$92 million (December 31, 2014 - US\$105 million) was recognized in respect of site investigation and remediation and, based upon cost model analysis completed in 2014, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US\$169 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. In the three-year rate order issued by the PSC in June 2015, Central Hudson's authorization to defer all site investigation and remediation costs was reaffirmed and extended through June 2018.

Asbestos Litigation

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,350 asbestos cases have been raised, 1,167 remained pending as at December 31, 2015. Of the cases no longer pending against Central Hudson, 2,027 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding 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.

FortisBC Electric

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 notified its insurers, it has been advised by the Government of British Columbia that a response to the claim is not required at this time. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. 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.

RELATED-PARTY TRANSACTIONS

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 transactions for the years ended December 31, 2015 and 2014 are discussed below.

Upon completion of the Waneta Expansion in early April 2015, FortisBC Electric commenced purchasing capacity from the Waneta Expansion under terms of the 40-year WECA, as approved by the BCUC. Power purchased by FortisBC Electric from the Waneta Expansion in 2015 totalled approximately \$30 million. In addition, the Waneta Expansion pays FortisBC Electric for management services associated with the generating station, which totalled approximately \$7 million in 2015.

From time to time, the Corporation provides short-term financing to certain of its subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements, bearing interest at rates that approximate the Corporation's cost of short-term borrowing. In addition, the Corporation provided long-term financing to certain of its subsidiaries, bearing interest at rates that approximate the Corporation's cost of long-term debt. The majority of this long-term financing was repaid in 2015 as a result of the sale of commercial real estate and hotel assets. As at December 31, 2015, inter-segment loans outstanding totalled \$48 million (December 31, 2014 - \$402 million) and total interest charged in 2015 was \$17 million (2014 - \$27 million).

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2015, 2014 and 2013.

Selected Annual Financial Information Years Ended December 31 (\$ millions, except per share amounts)	2015	2014	2013
Revenue	6,727	5,401	4,047
Net earnings	840	390	420
Net earnings attributable to common equity shareholders	728	317	353
Basic earnings per common share	2.61	1.41	1.74
Diluted earnings per common share	2.59	1.40	1.73
Total assets	28,804	26,233	17,908
Long-term debt (excluding current portion)	10,784	9,911	6,424
Preference shares	1,820	1,820	1,229
Common shareholders' equity	8,060	6,871	4,772
Dividends declared per common share	1.43	1.30	1.25
Dividends declared per First Preference Share, Series C ⁽¹⁾	-	-	0.4862
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⁾	0.9708	0.9708	1.1416
Dividends declared per First Preference Share, Series H ⁽³⁾	0.7344	1.0625	1.0625
Dividends declared per First Preference Share, Series I ⁽³⁾	0.3637	-	-
Dividends declared per First Preference Share, Series J	1.1875	1.1875	1.1875
Dividends declared per First Preference Share, Series K ⁽⁴⁾	1.0000	1.0000	0.6233
Dividends declared per First Preference Share, Series M ⁽⁵⁾	1.0250	0.4613	-

⁽¹⁾ In July 2013 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series C.

⁽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⁾ On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. The annual fixed dividend per share for the First Preference Shares, Series H was reset from \$1.0625 to \$0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020. The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

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

⁽⁵⁾ The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 and are entitled to receive cumulative dividends in the amount of \$1.0250 per share per annum for the first five years.

2015/2014: Revenue increased \$1,326 million, or 24.6%, from 2014 and net earnings attributable to common equity shareholders were \$728 million, or \$2.61 per common share, compared to \$317 million, or \$1.41 per common share, in 2014. For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders, and earnings per common share, refer to the "Consolidated Results of Operations" and "Summary Financial Highlights" sections of this MD&A.

The growth in total assets reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets in 2015. The increase in long-term debt was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely to finance energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated long-term debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.

2014/2013: Revenue increased \$1,354 million, or 33.5%, from 2013. The increase in revenue was driven by the acquisition of UNS Energy in August 2014 and Central Hudson in June 2013. A higher commodity cost of natural gas charged to customers at FortisBC Energy, an increase in the base component of rates at most of the regulated utilities and higher electricity sales also contributed to the increase in revenue.

Net earnings attributable to common equity shareholders were \$317 million in 2014 compared to \$353 million in 2013. Results for both years were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014 and Central Hudson in 2013. Earnings for 2014 were reduced by \$39 million due to acquisition-related expenses and customer benefits offered to obtain regulatory approval of the acquisition of UNS Energy, compared to \$34 million associated with the acquisition of Central Hudson in 2013. Interest expense of \$51 million after tax, including the make-whole payment, associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy was recognized in 2014. In addition, 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, an extraordinary gain of \$20 million related to the settlement of expropriation matters associated with the Exploits River Hydro Partnership, and the release of income tax provisions of approximately \$7 million. An \$8 million foreign exchange gain was recognized in 2014 compared to \$6 million in 2013. Earnings for 2014 included \$5 million associated with Griffith to the date of sale, and earnings for 2013 were reduced by \$5 million associated with Griffith.

Excluding the above-noted impacts, net earnings attributable to common equity shareholders for 2014 were \$394 million, an increase of \$58 million from \$336 million for 2013. The increase was driven by \$60 million of earnings contribution at UNS Energy from the date of acquisition and the first full year of earnings contribution from Central Hudson, which was acquired in June 2013. Rate base growth and an increase in the number of customers at FortisAlberta and electricity sales growth at Caribbean Regulated Electric Utilities also contributed to the increase. The increase was partially offset by lower earnings at FortisBC Electric, primarily due to the impact of lower-than-expected finance charges in 2013 and higher Corporate and Other expenses. The increase in Corporate and Other expenses was primarily due to higher finance charges, largely due to the acquisitions of UNS Energy and Central Hudson, and higher operating expenses, partially offset by a higher income tax recovery and interest income.

The growth in total assets reflects the Corporation's acquisition of UNS Energy in August 2014 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 UNS Energy, including debt assumed on acquisition, and the financing of energy infrastructure investments.

Basic earnings per common share were \$1.41 in 2014 compared to \$1.74 in 2013. Excluding the above-noted non-recurring items in 2014 and 2013, basic earnings per common share were \$1.75 for 2014, an increase of \$0.09 from \$1.66 for 2013. The increase was driven by accretion associated with the acquisition of UNS Energy.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2015 and 2014.

Summary of Gas Volumes and Electricity and Energy Sales			
Fourth Quarters Ended December 31 (<i>Unaudited</i>)	2015	2014	Variance
Regulated Electric & Gas Utilities - United States			
UNS Energy - Electricity Sales (<i>GWh</i>)	3,562	3,583	(21)
UNS Energy - Gas Volumes (<i>PJ</i>)	4	4	-
Central Hudson - Electricity Sales (<i>GWh</i>)	1,160	1,176	(16)
Central Hudson - Gas Volumes (<i>PJ</i>)	5	5	-
Regulated Gas Utility - Canadian			
FortisBC Energy (<i>PJ</i>)	62	59	3
Regulated Electric Utilities - Canadian			
FortisAlberta (<i>GWh</i>)	4,188	4,446	(258)
FortisBC Electric (<i>GWh</i>)	836	846	(10)
Eastern Canadian (<i>GWh</i>)	2,189	2,203	(14)
Regulated Electric Utilities - Caribbean (<i>GWh</i>)	201	187	14
Non-Regulated - Fortis Generation (<i>GWh</i>)	122	109	13

Gas Volumes

The increase in gas volumes at FortisBC Energy was mainly due to higher gas volumes for transportation customers due to certain customers switching to natural gas compared to alternative fuel sources.

Electricity and Energy Sales

The decrease in energy deliveries at FortisAlberta was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas. At most of the other regulated electric utilities, the decrease was mainly due to lower average consumption due to warmer temperatures, which reduced heating requirements. At the Regulated Electric Utilities – Caribbean, the impact of warmer temperatures increased electricity sales, due to higher air conditioning load. The overall decrease was partially offset by higher non-regulated energy sales, driven by the Waneta Expansion.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders						
Fourth Quarters Ended December 31 (Unaudited)						
(\$ millions, except per share amounts)	Revenue			Net Earnings		
	2015	2014	Variance	2015	2014	Variance
Regulated Electric & Gas Utilities - United States						
UNS Energy	482	435	47	26	23	3
Central Hudson	202	186	16	15	4	11
	684	621	63	41	27	14
Regulated Gas Utility - Canadian						
FortisBC Energy	411	432	(21)	65	49	16
Regulated Electric Utilities - Canadian						
FortisAlberta	140	132	8	29	25	4
FortisBC Electric	99	90	9	8	12	(4)
Eastern Canadian Electric Utilities	273	266	7	15	14	1
	512	488	24	52	51	1
Regulated Electric Utilities - Caribbean	82	84	(2)	9	6	3
Non-Regulated - Fortis Generation	30	8	22	11	4	7
Non-Regulated - Non-Utility	6	62	(56)	1	7	(6)
Corporate and Other	2	7	(5)	(44)	(31)	(13)
Inter-Segment Eliminations	(19)	(9)	(10)	-	-	-
Total	1,708	1,693	15	135	113	22
Basic Earnings per Common Share (\$)				0.48	0.44	0.04

Revenue

The increase in revenue was mainly due to favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion, and an increase in base electricity rates at the Canadian Regulated Electric Utilities. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets.

Earnings

The increase in earnings was primarily due to: (i) favourable foreign exchange impacts; (ii) an increase in base electricity rates at Central Hudson effective July 1, 2015, combined with the impact of storm restoration and other non-recurring expenses recognized in the fourth quarter of 2014; (iii) earnings contribution of approximately \$6 million from the Waneta Expansion; (iv) rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta; and (v) a higher AFUDC at FortisBC Energy, partially offset by higher operating expenses. The timing of regulatory deferral mechanisms had a favourable impact on FortisBC Energy's earnings for the quarter and an unfavourable impact on FortisBC Electric. The increase in earnings was partially offset by lower earnings contribution due to the sale of commercial real estate and hotel assets and higher Corporate and Other expenses. Corporate and Other expenses included \$7 million in acquisition-related expenses in the fourth quarter of 2015 and in the fourth quarter of 2014 included \$4 million in interest expense associated with the convertible debentures and a \$3 million foreign exchange gain. Excluding these items, the increase in Corporate and Other expenses was mainly due to a lower income tax recovery and lower related-party interest income.

Summary of Consolidated Cash Flows			
Fourth Quarters Ended December 31 <i>(Unaudited)</i>			
<i>(\$ millions)</i>	2015	2014	Variance
Cash, Beginning of Period	347	458	(111)
Cash Provided by (Used in):			
Operating Activities	397	334	63
Investing Activities	(234)	(829)	595
Financing Activities	(280)	257	(537)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	12	10	2
Cash, End of Period	242	230	12

Cash flow from operating activities was \$63 million higher quarter over quarter. The increase was primarily due to higher cash earnings at the Corporation's regulated utilities.

Cash used in investing activities was \$595 million lower quarter over quarter. The decrease was mainly due to lower capital expenditures at the regulated utilities, largely due to UNS Energy's purchase of Gila River Unit 3 generation station in December 2014 for approximately \$252 million (US\$219 million), and proceeds received from the sale of hotel assets in October 2015 for \$365 million.

Cash provided by financing activities was \$537 million lower quarter over quarter. The decrease was primarily due to the repayment of credit facility borrowings in the fourth quarter of 2015 using proceeds from the sale of hotel assets. In addition, lower proceeds from long-term debt and lower credit facility borrowings were partially offset by lower repayments of long-term debt. In the fourth quarter of 2014, proceeds from the second installment of the convertible debentures were received, which were used to repay acquisition credit facilities used initially to finance a portion of the acquisition of UNS Energy.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2014 through December 31, 2015. 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)	Net Earnings Attributable to Common Equity		Earnings per Common Share	
	Revenue	Shareholders	Basic	Diluted
Quarter Ended	<i>(\$ millions)</i>	<i>(\$ millions)</i>	<i>(\$)</i>	<i>(\$)</i>
December 31, 2015	1,708	135	0.48	0.48
September 30, 2015	1,566	151	0.54	0.54
June 30, 2015	1,538	244	0.88	0.87
March 31, 2015	1,915	198	0.72	0.71
December 31, 2014	1,693	113	0.44	0.43
September 30, 2014	1,197	14	0.06	0.06
June 30, 2014	1,056	47	0.22	0.22
March 31, 2014	1,455	143	0.67	0.66

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions and associated acquisition-related expenses, and the impact of sale transactions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity and gas demand in different regions, 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 FortisBC Energy are realized in the first and fourth quarters. Earnings for UNS Energy's electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

December 2015/December 2014: Net earnings attributable to common equity shareholders were \$135 million, or \$0.48 per common share, for the fourth quarter of 2015 compared to earnings of \$113 million, or \$0.44 per common share, for the fourth quarter of 2014. A discussion of the variances in financial results for the fourth quarter of 2015 and the fourth quarter of 2014 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2015/September 2014: Net earnings attributable to common equity shareholders were \$151 million, or \$0.54 per common share, for the third quarter of 2015 compared to earnings of \$14 million, or \$0.06 per common share, for the third quarter of 2014. Earnings for the third quarter of 2015 were favourably impacted by a \$5 million gain on the sale of non-regulated generation assets in Ontario and a \$5 million positive adjustment associated with the sale of hotel assets, and were reduced by a \$9 million loss on the settlement of expropriation matters related to the Corporation's investment in Belize Electricity. Earnings for the third quarter of 2014 were reduced by a total of \$58 million due to acquisition-related expenses associated with UNS Energy. Excluding these items, the increase in earnings was driven by contribution of \$97 million at UNS Energy compared to \$37 million for the third quarter of 2014. Earnings contribution of \$5 million from the Waneta Expansion also contributed to the increase. Performance was also driven by the Corporation's other regulated utilities, including rate base growth associated with capital expenditures and customer growth at FortisAlberta; improved performance at Central Hudson; and favourable foreign exchange associated with US dollar-denominated earnings. Earnings at FortisBC Energy and FortisBC Electric were impacted by the timing of regulatory deferral mechanisms; however, FortisBC Energy's earnings were favourably impacted by lower operating expenses and higher AFUDC. The increase was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy.

June 2015/June 2014: Net earnings attributable to common equity shareholders were \$244 million, or \$0.88 per common share, for the second quarter of 2015 compared to earnings of \$47 million, or \$0.22 per common share, for the second quarter of 2014. The increase was driven by a net gain of \$123 million on the sale of commercial real estate, hotel and non-regulated generation assets. The increase was also due to earnings contribution of \$52 million at UNS Energy and \$12 million from the Waneta Expansion, representing the Corporation's 51% controlling ownership. Performance was also driven by the Corporation's regulated utilities, including rate base growth associated with capital expenditures, customer growth and a decrease in depreciation and amortization at FortisAlberta; increases at FortisBC Electric, largely due to timing of quarterly earnings compared to the same periods last year, resulting from the impact of regulatory deferral mechanisms; and improved performance at Central Hudson. The increase was partially offset by a \$5 million decrease in earnings at FortisBC Energy due to the timing of regulatory flow-through deferral amounts, and higher preference share dividends and finance charges in the Corporate and Other segment associated with the acquisition of UNS Energy.

March 2015/March 2014: Net earnings attributable to common equity shareholders were \$198 million, or \$0.72 per common share, for the first quarter of 2015 compared to earnings of \$143 million, or \$0.67 per common share, for the first quarter of 2014. The increase in earnings was driven by the Corporation's regulated utilities. UNS Energy contributed earnings of \$20 million in the first quarter of 2015. FortisAlberta's earnings were favourably impacted by higher capital tracker revenue, including approximately \$10 million associated with 2013 and 2014, and customer growth. Earnings at FortisBC Energy and FortisBC Electric were \$9 million and \$5 million, respectively, higher quarter over quarter, largely due to timing of quarterly earnings compared to the same periods last

year resulting from the impact of regulatory deferral mechanisms. Central Hudson and Eastern Canadian Regulated Electric Utilities also reported improved performance. The increase in earnings at the regulated utilities was partially offset by lower earnings at the Corporation's non-regulated subsidiaries, largely due to decreased production in Belize as a result of lower rainfall, costs at Fortis Properties associated with the strategic review, and approximately \$5 million earnings contribution in the first quarter of 2014 from Griffith to the date of sale. Corporate and Other expenses were lower quarter over quarter, due to approximately \$11 million in after-tax interest expense associated with the convertible debentures in the first quarter of 2014 and a higher foreign exchange gain, partially offset by higher preference share dividends and finance charges associated with the acquisition of UNS Energy.

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

Disclosure Controls and Procedures: The President and Chief Executive Officer ("CEO") and the Executive Vice President, 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, 2015 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, 2015 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2015, 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 EVENT

On February 9, 2016, Fortis and ITC entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction valued at approximately US\$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. Under the terms of the transaction, ITC shareholders will receive US\$22.57 in cash and 0.7520 Fortis common shares per ITC common share, representing total consideration of approximately US\$6.9 billion, and Fortis will assume approximately US\$4.4 billion of ITC consolidated indebtedness.

ITC is the largest independent pure-play electric transmission company in the United States. ITC owns and operates high-voltage transmission facilities in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, serving a combined peak load exceeding 26,000 MW along approximately 15,600 miles of transmission line. In addition, ITC is a public utility and independent transmission owner in Wisconsin. ITC's tariff rates are regulated by FERC, which has been one of the most consistently supportive utility regulators in North America providing reasonable returns and equity ratios. Rates are set using a forward-looking rate-setting mechanism with an annual true-up, which provides timely cost recovery and reduces regulatory lag.

The closing of the Acquisition is subject to ITC and Fortis shareholder approvals, the satisfaction of other customary closing conditions, and certain regulatory, state and federal approvals including, among others, those of FERC, the Committee on Foreign Investment in the United States, and the United States Federal Trade Commission/Department of Justice under the *Hart-Scott Rodino Antitrust Improvement Act*. The closing of the Acquisition is expected to occur in late 2016.

The pending Acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The Acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix. On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately \$8 billion to approximately \$26 billion, as a result of the Acquisition.

The financing of the Acquisition has been structured to allow Fortis to maintain investment-grade credit ratings and is consistent with the Corporation's existing capital structure. Financing of the cash portion of the Acquisition will be achieved primarily through the issuance of approximately US\$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. In addition, Fortis has obtained commitments of US\$2.0 billion from Goldman Sachs Bank USA to bridge the long-term debt financing and US\$1.7 billion from The Bank of Nova Scotia to primarily bridge the sale of the minority investment in ITC. These non-revolving term credit facilities are repayable in full on the first anniversary of their advance, and although syndication is not required, Fortis expects that these bridge facilities will be syndicated.

Upon completion of the Acquisition, ITC will become a subsidiary of Fortis and approximately 27% of the common shares of Fortis will be held by ITC shareholders. In connection with the Acquisition, Fortis will become a registrant with the SEC and will apply to list its common shares on the New York Stock Exchange and will continue to have its shares listed on the TSX.

OUTLOOK

Fortis is focused on closing the acquisition of ITC by the end of 2016. The Acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The Acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix.

Substantially all of Fortis' assets are low-risk, regulated utilities and long-term contracted energy infrastructure. No single regulatory jurisdiction comprises more than one-third of total assets. Over the five-year period through 2020, excluding the acquisition of ITC, the Corporation's highly executable capital program is expected to be approximately \$9 billion. This investment in energy infrastructure is expected to increase rate base to almost \$21 billion in 2020 and produce a five-year compound annual growth rate in rate base of approximately 5%.

On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately \$8 billion to approximately \$26 billion, as a result of the acquisition of ITC. Following the Acquisition, Fortis will be one of the top 15 North American public utilities ranked by enterprise value, with an estimated enterprise value of \$42 billion. Additionally, ITC's midyear rate base, including construction work in progress, is expected to increase at a compound annual growth rate of approximately 7.5% through 2018, based on ITC's planned capital expenditure program.

Fortis continues to target 6% average annual dividend growth through 2020. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance.

Fortis expects long-term sustainable growth in rate base, assets and earnings resulting from strategic acquisitions and investment in its existing utility operations. The Corporation is also committed to identifying and executing on opportunities for incremental rate base and earnings growth through additional investments in existing service territories, and in new franchise areas.

OUTSTANDING SHARE DATA

As at February 16, 2016, the Corporation had issued and outstanding 281.9 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; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M. 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 and First Preference Shares, Series E were converted as at February 16, 2016 is as follows.

Conversion of Securities into Common Shares	
As at February 16, 2016 (Unaudited)	
Security	Number of Common Shares (millions)
Stock Options	4.9
First Preference Shares, Series E	5.8
Total	10.7

Additional information, including the Fortis 2015 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.