Management Discussion and Analysis

For the year ended December 31, 2017
Dated February 14, 2018

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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*. This MD&A should be read in conjunction with the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2017. Financial information for 2017 and comparative periods contained in this MD&A has been prepared in accordance with accounting principles generally accepted in the United States of America ("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 Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, collectively referred to as "forward-looking information". Forward-looking information included in the MD&A reflect expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which include, without limitation: the expectation that the Corporation will remain at the forefront of emerging technologies; the Corporation's forecast gross consolidated and segmented capital expenditures for 2018 and for the period 2018 through 2022 and expected associated increase to rate base; expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to long-term capital in 2018; targeted average annual dividend growth through 2022; expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; statements related to Fortis Turks and Caicos' recovery of lost revenue as a result of the impact of Hurricane Irma and the timing thereof; the nature, timing, funding sources and expected costs of certain capital projects including, without limitation, the ITC Multi-Value Regional Transmission Projects and 34.6 to 69 kV Conversion Project, UNS Energy flexible generation resource investment and Gila River Generating Station Unit 2, FortisBC Energy expansion of the Tilbury liquefied natural gas ("LNG") facility, Eagle Mountain Woodfibre Gas Pipeline Project, Lower Mainland System Upgrade and Pipeline Integrity Management Program and additional opportunities beyond the base plan including the Wataynikaneyap Project, the Lake Erie Connector Project and additional LNG infrastructure investment in British Columbia; the expectation that subsidiary operating expenses and interest costs will be paid out of subsidiary operating cash flows; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from

Fortis; the expectation that maintaining the targeted capital structure of the Corporation's regulated operating subsidiaries will not have an impact on its ability to pay dividends in the foreseeable future; the expectation that cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions will 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; expected consolidated fixed-term debt maturities and repayments in 2018 and over the next five years; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout 2018; statements related to the at-the-market program including but not limited to the timing, receipt of regulatory approvals and the entering into agreements with agents; the intent of management to refinance certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities with long-term permanent financing; the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements; the impact of U.S. Tax Reform on the Corporation's annual earnings per share and cash flows at the Corporation's U.S. regulated utilities and rate base growth; and the expectation that long-term sustainable growth in rate base will support continuing growth in earnings and dividends.

Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: 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; 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 changes in tax laws; 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, environmental laws and regulations that may materially negatively affect the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the continued tax deferred treatment of earnings from the Corporation's foreign operations; continued maintenance of information technology infrastructure and no material breach of cyber-security; 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.

Forward-looking information involves significant risks, uncertainties and assumptions. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on 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 and the Securities and Exchange Commission. Key risk factors for 2018 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; the impact of fluctuations in foreign exchange rates; the impact of the Tax Cuts and Jobs Act on the Corporation's future results of operations and cash flows; risk associated with the impacts of less favourable economic conditions on the Corporation's results of operations; risk associated with the Corporation's ability to continue to comply with Section 404(a) of the Sarbanes-Oxley Act of 2002 and the related rules of the U.S. Securities and Exchange Commission and the Public Company Accounting Oversight Board; risk associated with the completion of the Corporation's 2018 capital expenditure program, including completion of major capital projects in the timelines anticipated and at the expected amounts; and uncertainty in the timing and access to capital markets to arrange sufficient and cost-effective financing to finance, among other things, capital expenditures and the repayment of maturing debt.

All forward-looking information in the MD&A is given as of the date of the MD&A and Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

CORPORATE OVERVIEW

Fortis is a leader in the North American regulated electric and gas utility business, with 2017 revenue of $8.3 billion and total assets of approximately $48 billion. Approximately 8,500 employees of the Corporation serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. In 2017 the Corporation's electricity systems met a combined peak demand of 32,134 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,585 terajoules.

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's utilities are primarily determined under cost of service ("COS") regulation, in combination with performance-based rate-setting ("PBR") mechanisms in certain jurisdictions. 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") may depend 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, as applicable; (vi) regulatory lag in the case of a historical test year; and (vii) foreign exchange rates. 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 business based on regulatory status and service territory, as well as the information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of the 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 responsibility for net earnings and its own resource allocation.

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

Regulated Utilities - United States

a. *ITC*: Primarily comprised of ITC Holdings Corp. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC, (collectively "ITC"). ITC was acquired by Fortis in October 2016, with Fortis owning 80.1% of ITC and an affiliate of GIC Private Limited ("GIC") owning a 19.9% minority interest. Also included in the ITC segment is the net corporate expenses and activity of ITC Investment Holdings.

   ITC owns and operates high-voltage transmission lines, in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, that transmit electricity from generating stations to local distribution facilities connected to ITC's systems.

b. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively "UNS Energy").

   UNS Energy's largest operating subsidiary, TEP, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 422,000 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 96,000 retail customers in Arizona's Mohave and Santa Cruz counties. TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,834 MW, including 64 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, 2017, approximately 44% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility, serving approximately 156,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

c. *Central Hudson:* Primarily comprised of Central Hudson Gas & Electric Corporation ("Central Hudson"), which is a regulated electric and gas transmission and distribution utility, serving approximately 300,000 electricity customers and 80,000 natural gas customers in portions of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW. Also included in the Central Hudson segment is the net corporate expenses and activity of CH Energy Group, Inc. ("CH Energy Group").

Regulated Utilities - Canada

a. *FortisBC Energy:* FortisBC Energy Inc. ("FortisBC Energy") is the largest regulated distributor of natural gas in British Columbia, serving approximately 1,008,000 customers in more than 135 communities. FortisBC Energy provides transmission and distribution 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 FortisBC Energy's Southern Crossing pipeline, from Alberta.

b. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") is a regulated electricity distribution utility serving approximately 556,000 customers, in a substantial portion of southern and central Alberta. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

c. *FortisBC Electric*: Includes FortisBC Inc. ("FortisBC Electric"), an integrated regulated electric utility operating in the southern interior of British Columbia, serving approximately 172,000 customers directly and indirectly. FortisBC Electric 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 five hydroelectric generating facilities in British Columbia primarily owned by third parties, one of which is the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT").

d. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric"), FortisOntario Inc. ("FortisOntario"), and the Corporation's 49% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Partnership").

   Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 266,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island, serving approximately 80,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 145 MW. FortisOntario is comprised of three regulated electric utilities that provide service to approximately 66,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. Wataynikaneyap Partnership is a partnership between 22 First Nation communities and Fortis with a mandate of connecting remote First Nation communities to the electricity grid in Ontario through the development of new transmission lines (the "Wataynikaneyap Power Project"). The Wataynikaneyap Power Project is in the development stage.

Regulated Utilities – Caribbean

Caribbean: Includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2016 - 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity"). Caribbean Utilities is an integrated regulated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 29,000 customers. Caribbean Utilities has an installed diesel-powered generating capacity of 161 MW. Fortis Turks and Caicos is comprised of two integrated regulated electric utilities serving approximately 15,000 customers on certain islands in Turks and Caicos. Fortis Turks and Caicos has a combined diesel-powered generating capacity of 84 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

Energy Infrastructure: Primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion, conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The output is sold to BC Hydro and FortisBC Electric under 40-year contracts. Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW, conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Aitken Creek Gas Storage ULC, acquired by Fortis in April 2016, owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet.

In 2016 the Corporation sold its 16-MW run-of-river Walden hydroelectric generating facility.

Corporate and Other: 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").

CORPORATE STRATEGY

Fortis is a leader in the North American utility industry and its strategic vision is to provide safe, reliable and cost-effective energy service to customers, while delivering long-term profitable growth. The Corporation is a well-diversified, regulated, primarily transmission and distribution business characterized by low-risk, stable and predictable earnings and cash flows.

Earnings per common share and total shareholder return are the primary measures of financial performance. Over the 10-year period ended December 31, 2017, earnings per common share of Fortis grew at a compound annual growth rate of 5.2%. Over the same period, Fortis delivered an average annualized total return to shareholders of 8.8%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 5.6% and 4.7%, respectively, over the same period.

The Corporation is committed to achieving long-term sustainable growth in rate base and earnings resulting from investment in existing utility operations. Management remains focused on executing the consolidated capital expenditure program and pursuing additional investment opportunities within existing service territories, and the Corporation's standalone operating model positions it well for such future investment opportunities. The Corporation maintains a small head office and its utilities operate on a substantially autonomous basis. Each of the utilities has its own management team and most have oversight by a Board of Directors comprised of a majority of independent directors. Given that regulatory oversight is usually state or provincially based, the Corporation believes this model provides superior transparency and best serves the interests of customers.

KEY TRENDS, RISKS AND OPPORTUNITIES

Energy Industry Developments: The North American energy industry continues to transform. There is a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. 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.

Changing energy policies at the federal, state and provincial levels is creating volatility in certain jurisdictions by introducing uncertainty around environmental, tax and trade policies. The regulatory and compliance operating environment also continues to evolve and is becoming increasingly complex. Such changing policies and regulations create additional opportunities to expand investment in new generation sources, including natural gas and solar and wind generation, as well as infrastructure to interconnect renewable energy sources to the grid. The Corporation's regulated utilities are well positioned and actively involved in pursuing these opportunities.

New technology is driving change across all service territories. Energy delivery systems are being upgraded with advanced meters, improved controls and more capable operational technology, providing utilities with detailed usage data. Energy management capabilities are expanding through emerging storage and demand response systems and customers have become empowered to gain options to manage and reduce energy usage and access more affordable distributed generation technology. While some of these new technologies challenge the traditional role of utilities as one-way service providers, they also offer opportunities to improve and expand services through strategic investments. Such investments in information and operational technology, the exponential growth in data and interconnections to the electricity systems, and the more volatile international security atmosphere are driving the need for increased cyber and physical security systems.

Meaningful customer engagement is becoming increasingly important for utilities. Customers want to make informed energy choices and become active participants in their energy services with the end result of reducing energy costs. Utilities can increase customer value by providing accurate, balanced energy information that is relevant and enables customer choices and action. This creates an opportunity for utilities to become trusted energy partners in an evolving energy market.

Utility customer expectations are also changing with competition for consumer attention becoming increasingly intense. Utility customers expect personalized service, customized service offerings and more real-time, digital communications. The Corporation's utilities are well positioned to satisfy changing customer needs by leveraging new technology.

Despite the challenges facing the utility industry, Fortis is well positioned to capitalize on any resulting opportunities. Its decentralized structure and customer-focused business culture will support the efforts required to meet evolving customer expectations and to work with policy makers and regulators on solutions that are financially sustainable for the utilities. Fortis is also a strategic partner in the Energy Impact Partners utility coalition, which is a private firm that invests in emerging technologies, products, services and business models across the full electricity supply chain. Leveraging these relationships and partnerships, Fortis will remain at the forefront of emerging technologies to meet the evolving challenges in the ever-changing utility industry.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's utilities is subject to regulation by the regulatory authority in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level and Fortis is well positioned to maintain constructive regulatory relationships through local management teams and boards comprised of mostly independent local board members. Commitment by the Corporation's utilities to provide safe and reliable service, operational excellence and promote positive customer and regulatory relations is also important to ensure supportive regulatory relationships and obtain full cost recovery and competitive returns for the Corporation's shareholders.

In 2017, the Arizona Corporation Commission ("ACC") issued a Rate Order for new rates for TEP that took effect February 27, 2017. The provisions of the Rate Order include, but are not limited to, an increase in non-fuel base revenue of $108 million (US$81.5 million), an allowed ROE of 9.75%, and a common equity component of capital structure of approximately 50%. At ITC, uncertainty remains regarding the final outcome of the Midcontinent Independent System Operator ("MISO") ROE Complaints and the timing of completion of these matters.

In February 2018 the Alberta Utilities Commission ("AUC") issued a decision to establish the going-in revenue requirement and capital funding mechanism for FortisAlberta's second PBR term from 2018 to 2022. The decision did not grant certain cost items requested by the utilities in Alberta. A compliance filing related to the decision is due to be filed with the regulator by March 1, 2018. The earnings per share impact for Fortis is expected to be minimal.

All of the Corporation's regulated utilities continue to be actively engaged with each of their regulators and are focused on maintaining constructive regulatory relationships and outcomes. For a further discussion of 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 2017 was $25.4 billion. Over the five-year period through 2022, the Corporation's capital expenditure program is expected to be approximately $14.5 billion. This investment in energy infrastructure is expected to increase rate base to over $32 billion by 2022 and produce a five-year compound annual growth rate in rate base of approximately 5%. The three-year compound annual growth rate in rate base through 2020 is expected to be approximately 6%, reflecting greater visibility in capital expenditures in the first three years of the capital expenditure program. Fortis expects this capital investment to support growth in earnings and dividends.

For further information on the Corporation's consolidated capital expenditure program and the 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, 2017, approximately 80% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately $650 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital expenditure programs and working capital requirements, the Corporation and its subsidiaries have approximately $5.0 billion in credit facilities, of which approximately $3.9 billion was unused as at December 31, 2017. Based on current credit ratings and capital structures, the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2018.

Dividend Increases: Dividends paid per common share increased to $1.625 in 2017. In 2017 Fortis increased its quarterly dividend per common share by 6.25% to $0.425 per quarter, or $1.70 on an annualized basis. This continues the Corporation's track record of raising its annualized dividend to common shareholders for 44 consecutive years.

Fortis also extended its dividend guidance, targeting average annual dividend per common share growth of 6% through 2022. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its $14.5 billion five-year capital expenditure program, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence.

SIGNIFICANT ITEM

U.S. Tax Reform: On December 22, 2017, the *Tax Cuts and Jobs Act* was signed into law by the President of the United States of America, enacting significant changes to tax legislation ("U.S. Tax Reform"). The changes included a reduction in the federal corporate income tax rate from 35% to 21% effective January 1, 2018, and certain provisions relating specifically to the utility industry, including the continuation of certain interest expense deductibility and the elimination of 100% expensing of capital investments, referred to as bonus depreciation. The Corporation's U.S. subsidiaries were required to remeasure their deferred income tax assets and liabilities, including U.S. federal income tax net operating losses, at the new corporate income tax rate as at the date of enactment. The one-time remeasurement resulted in a net decrease in deferred income tax liabilities of $1.3 billion, the recognition of a regulatory liability of $1.5 billion for the reduction in deferred income tax expected to be refunded to customers, and an unfavourable earnings impact of $168 million recognized in deferred income tax expense ($146 million after non-controlling interest).

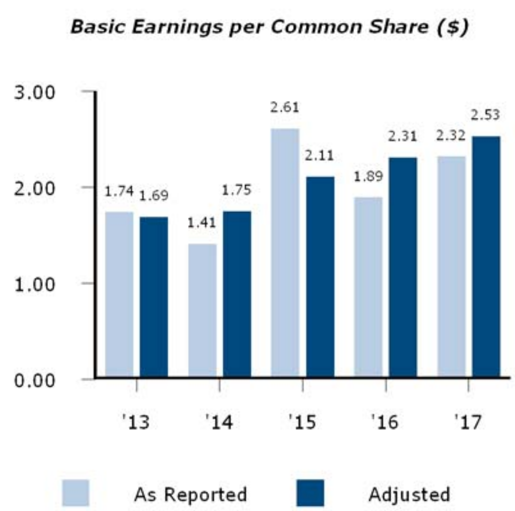
SUMMARY FINANCIAL HIGHLIGHTS

For the Years Ended December 31	**2017**	2016	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**963**	585	378
Basic Earnings per Common Share *($)*	**2.32**	1.89	0.43
Adjusted Basic Earnings per Common Share *($)* [(1)]	**2.53**	2.31	0.22
Weighted Average Number of Common Shares Outstanding *(millions)*	**415.5**	308.9	106.6
Cash Flow from Operating Activities *($ billions)*	**2.8**	1.9	0.9
Dividends Paid per Common Share *($)*	**1.625**	1.525	0.10
Total Assets *($ billions)*	**47.8**	47.9	(0.1)
Capital Expenditures *($ billions)*	**3.0**	2.1	0.9
Long-Term Debt Offerings *($ billions)*	**2.5**	4.1	(1.6)

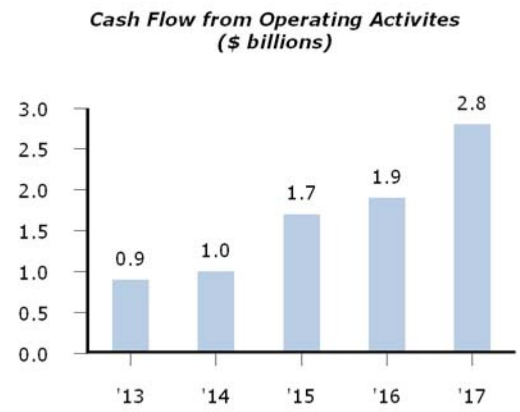
[(1)] Adjusted basic earnings per common share is a non-US GAAP measure. For a definition and reconciliation of this non-US GAAP measure, refer to the "Consolidated Results of Operations" section of this MD&A.

Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $963 million in 2017 compared to $585 million in 2016. The increase was driven by a full year of earnings contribution at ITC, which was acquired in October 2016, lower Corporate and Other expenses, strong performance at UNS Energy, and higher earnings from Aitken Creek.

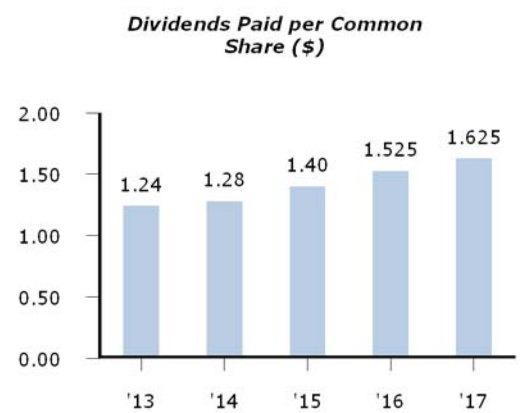
Basic Earnings per Common Share: Basic earnings per common share were $2.32 in 2017 compared to $1.89 in 2016. The impact of higher net earnings attributable to common equity shareholders was partially offset by an increase in the weighted average number of common shares outstanding associated with the financing of the acquisition of ITC and the Corporation's dividend reinvestment and other share plans.



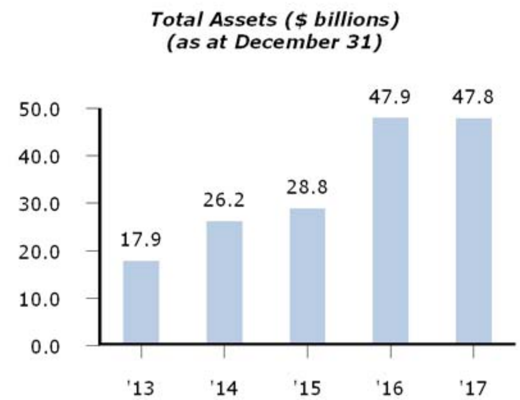
Cash Flow from Operating Activities: Cash flow from operating activities was $2.8 billion for 2017, an increase of $0.9 billion, or 47%, compared to 2016. The increase was primarily due to higher cash earnings, driven by ITC and UNS Energy, and the Corporation's acquisition-related transaction costs in 2016. Favourable changes in long-term regulatory deferrals were offset by unfavourable changes in working capital.



Dividends: Dividends paid per common share increased to $1.625 in 2017, approximately 6% higher than $1.525 in 2016. During 2017 Fortis increased its quarterly dividend per common share by 6.25% to $0.425 per quarter.



Total Assets: Total assets of approximately $47.8 billion at the end of 2017 were comparable to total assets at the end of 2016. The impact of unfavourable foreign exchange on the translation of US dollar-denominated assets was largely offset by continued investment in energy infrastructure, driven by capital spending at the regulated utilities.



Capital Expenditures: Consolidated capital expenditures were $3.0 billion in 2017 compared to $2.1 billion in 2016. Consolidated capital expenditures for 2017 were consistent with the Corporation's 2017 forecast of $3.0 billion, as disclosed in the MD&A for the year ended December 31, 2016. The increase in capital expenditures from 2016 was driven by capital spending at ITC and higher capital spending at most of the Corporation's regulated utilities. 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 $2.5 billion in long-term debt in 2017, largely in support of energy infrastructure investment and regularly scheduled debt repayments.

In October 2016, to finance a portion of the acquisition of ITC, the Corporation issued approximately 114.4 million common shares to shareholders of ITC, representing share consideration of approximately $4.7 billion. The net cash consideration totalled approximately $4.7 billion and was financed using: (i) net proceeds from the issuance of US$2.0 billion ($2.6 billion) unsecured notes in October 2016; (ii) net proceeds from GIC's US$1.228 billion ($1.6 billion) minority investment, which includes a shareholder note of US$199 million ($263 million); and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility.

In March 2017 approximately 12.2 million common shares of Fortis were issued to an institutional investor for proceeds of $500 million. The proceeds were used to repay short-term borrowings.

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

CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31 *($ millions)*	**2017**	2016	Variance
Revenue	**8,301**	6,838	1,463
Energy Supply Costs	**2,361**	2,341	20
Operating Expenses	**2,261**	2,031	230
Depreciation and Amortization	**1,179**	983	196
Other Income, Net	**127**	53	74
Finance Charges	**914**	678	236
Income Tax Expense	**588**	145	443
Net Earnings	**1,125**	713	412
Net Earnings Attributable to:			
Non-Controlling Interests	**97**	53	44
Preference Equity Shareholders	**65**	75	(10)
Common Equity Shareholders	**963**	585	378
Net Earnings	**1,125**	713	412
Basic Earnings per Common Share	**2.32**	1.89	0.43

Revenue
The increase in revenue was driven by the acquisition of ITC in October 2016. Higher revenue at UNS Energy, mainly due to the impact of the rate case settlement effective February 2017 and the overall favourable impact of transmission refunds ordered by the Federal Energy Regulatory Commission ("FERC"), and the flow through in customer rates of overall higher energy supply costs were partially offset by unfavourable foreign exchange associated with the translation of US dollar-denominated revenue.

Energy Supply Costs
The increase in energy supply costs was primarily due to overall higher commodity costs, partially offset by favourable foreign exchange associated with the translation of US dollar-denominated energy supply costs.

Operating Expenses
The increase in operating expenses was primarily due to the acquisition of ITC, and general inflationary and employee-related cost increases. The increase was partially offset by the receipt of a $28 million break fee ($24 million net of related transaction costs and tax) associated with the termination of the Waneta Dam purchase agreement in 2017, acquisition-related transaction costs of $132 million ($84 million after tax) in 2016 associated with ITC, and favourable foreign exchange associated with the translation of US dollar-denominated operating expenses.

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

Other Income, Net
The increase in other income, net of expenses, was primarily due to the acquisition of ITC and a one-time $21 million unrealized foreign exchange gain on a US dollar-denominated affiliate loan in 2017. The favourable settlement of matters at UNS Energy pertaining to FERC-ordered transmission refunds of $11 million ($7 million after tax) in 2017 also contributed to the increase.

Finance Charges
The increase in finance charges was primarily due to the acquisition of ITC, including interest expense on debt issued to complete the financing of the acquisition. The increase was partially offset by acquisition-related transaction costs of $39 million ($28 million after tax) in 2016 associated with ITC.

Income Tax Expense
The increase in income tax expense was primarily due to the acquisition of ITC, deferred income tax expense of $168 million as a result of U.S. Tax Reform and higher earnings before taxes.

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

The increase in net earnings attributable to common equity shareholders was driven by a full year of earnings contribution at ITC, which was acquired in October 2016. The increase was also due to: (i) lower Corporate and Other expenses, primarily due to the receipt of a break fee, net of related transaction costs, of $24 million associated with the termination of the Waneta Dam purchase agreement, a one-time $21 million unrealized foreign exchange gain on a US dollar-denominated affiliate loan, and $90 million in acquisition-related transactions costs in 2016 associated with ITC; (ii) strong performance at UNS Energy, largely due to the impact of the rate case settlement in February 2017 and the year over year favourable impact of $29 million associated with FERC-ordered transmission refunds; and (iii) higher earnings from Aitken Creek related to the unrealized gain on the mark-to-market of derivatives year over year and contribution for a full year in 2017. The increase was partially offset by: (i) deferred income tax expense of $168 million as a result of U.S. Tax Reform; (ii) higher finance charges associated with the acquisition of ITC; (iii) the favourable settlement of Springerville Unit 1 matters at UNS Energy in 2016; (iv) lower contribution from the Caribbean, mainly due to the impact of Hurricane Irma; and (v) unfavourable foreign exchange associated with the translation of US dollar-denominated earnings.

Earnings per common share were $0.43 higher year over year. The impact of the above-noted items on net earnings attributable to common equity shareholders was partially offset by an increase in the weighted average number of common shares outstanding associated with the financing of the acquisition of ITC and the Corporation's dividend reinvestment and share plans.

Adjusted Net Earnings Attributable to Common Equity Shareholders and Adjusted Basic Earnings per Common Share

Fortis uses financial measures, being adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share, that 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 adjustments presented by other companies. The most directly comparable US GAAP measures to adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share are net earnings attributable to common equity shareholders and basic earnings per common share, respectively.

The Corporation calculates adjusted net earnings attributable to common equity shareholders as net earnings attributable to common equity shareholders plus or minus items that management believes are not reflective of the normal, ongoing operations of the business. For the years ended December 31, 2017 and 2016, the Corporation adjusted net earnings attributable to common equity shareholders for: (i) deferred income tax expense as a result of U.S. Tax Reform; (ii) a one-time unrealized foreign exchange gain on an affiliate loan; (iii) an acquisition break fee; (iv) acquisition-related transaction costs; and (v) cumulative adjustments for regulatory decisions pertaining to prior periods considered to be outside the normal course of business for the periods presented.

The Corporation calculates adjusted basic earnings per common share by dividing adjusted net earnings attributable to common equity shareholders by the weighted average number of common shares outstanding.

The following table provides a reconciliation of the non-US GAAP measures. Each of the adjusting items are discussed in the segmented results of operations for the respective reporting segments.

Non-US GAAP Reconciliation Years Ended December 31 *($ millions, except for common share data)*	**2017**	2016	Variance
Net Earnings Attributable to Common Equity Shareholders	**963**	585	378
Adjusting Items:			
ITC -			
U.S. Tax Reform	**91**	—	91
Accelerated vesting of stock-based compensation awards	**—**	22	(22)
UNS Energy -			
U.S. Tax Reform	**5**	—	5
Settlement of FERC-ordered transmission refunds	**(11)**	—	(11)
FERC-ordered transmission refunds	**—**	18	(18)
Central Hudson -			
U.S. Tax Reform	**2**	—	2
Corporate and Other -			
U.S. Tax Reform	**48**	—	48
Unrealized foreign exchange gain on affiliate loan	**(21)**	—	(21)
Acquisition break fee	**(24)**	—	(24)
Acquisition-related transaction costs	**—**	90	(90)
Adjusted Net Earnings Attributable to Common Equity Shareholders	**1,053**	715	338
Adjusted Basic Earnings per Common Share *($)*	**2.53**	2.31	0.22
Weighted Average Number of Common Shares Outstanding *(# millions)*	**415.5**	308.9	106.6

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders Years Ended December 31 *($ millions)*	**2017**	2016	Variance
Regulated Utilities - United States			
ITC	**272**	59	213
UNS Energy	**270**	199	71
Central Hudson	**70**	70	—
Regulated Utilities - Canada			
FortisBC Energy	**154**	151	3
FortisAlberta	**120**	121	(1)
FortisBC Electric	**55**	54	1
Eastern Canadian	**64**	64	—
Regulated Utilities - Caribbean	**34**	46	(12)
Non-Regulated			
Energy Infrastructure	**94**	60	34
Corporate and Other	**(170)**	(239)	69
Net Earnings Attributable to Common Equity Shareholders	**963**	585	378

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the significant 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 2017 earnings from regulated utilities represented approximately 92% (2016 – 93%) of the Corporation's earnings from its operating segments, excluding Corporate and Other segment expenses. Total regulated utility assets represented approximately 97% of the Corporation's total assets as at December 31, 2017 (December 31, 2016 – 97%).

REGULATED UTILITIES – UNITED STATES

Regulated Utilities - United States earnings for 2017 were $612 million (2016 - $328 million), which represented approximately 59% of the Corporation's total regulated earnings (2016 - 43%). The increase in earnings was driven by the acquisition of ITC in October 2016. Total segment assets were approximately $29.4 billion as at December 31, 2017 (December 31, 2016 - $30.1 billion), which represented approximately 63% of the Corporation's total regulated assets as at December 31, 2017 (December 31, 2016 - 65%).

ITC

Financial Highlights (1) Years Ended December 31	**2017**	2016
Average US:CAD Exchange Rate (2)	**1.30**	1.34
Revenue *($ millions)*	**1,575**	334
Earnings *($ millions)*	**272**	59

(1) Revenue represents 100% of ITC, while earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflects consolidated purchase price accounting adjustments.
(2) The reporting currency of ITC is the US dollar. The average US:CAD exchange rate for 2016 is from October 14, 2016, the date of acquisition.

Revenue and Earnings
ITC was acquired by Fortis on October 14, 2016 and the comparative period reflects the financial results of ITC from the date of acquisition.

There were no transactions or events, outside the normal course of operations, which materially impacted ITC's revenue or earnings for 2017, with the exception of the enactment of U.S. Tax Reform, which resulted in a $91 million increase in deferred income tax expense. For further details on U.S. Tax Reform, refer to the "Significant Item" section of this MD&A.

UNS ENERGY

Financial Highlights Years Ended December 31	**2017**	2016	Variance
Average US:CAD Exchange Rate (1)	**1.30**	1.33	(0.03)
Electricity Sales *(gigawatt hours ("GWh"))*	**14,971**	14,387	584
Gas Volumes *(petajoules ("PJ"))*	**13**	13	—
Revenue *($ millions)*	**2,080**	2,002	78
Earnings *($ millions)*	**270**	199	71

(1) The reporting currency of UNS Energy is the US dollar.

Electricity Sales & Gas Volumes
The increase in electricity sales was primarily due to higher short-term wholesale sales as a result of more favourable commodity prices and higher long-term wholesale sales due to the commencement of a new contract in 2017. The majority of revenue from short-term wholesale sales is flowed through to customers and has no impact on earnings.

Gas volumes were comparable with 2016.

Revenue

The increase in revenue was due to: (i) the impact of the rate case settlement effective February 27, 2017; (ii) approximately $29 million ($18 million after tax) in FERC-ordered transmission refunds recognized in 2016; (iii) higher short-term wholesale sales; and (iv) the reversal of $7 million ($4 million after-tax) in transmission refund accruals in 2017. The increase was partially offset by: (i) approximately $41 million of unfavourable foreign exchange associated with the translation of US dollar-denominated revenue; (ii) $17 million ($10 million after tax) in revenue related to the settlement of Springerville Unit 1 matters in 2016; and (iii) lower revenue related to a decrease in fuel cost recovery rates in 2017, which has no impact on earnings.

Earnings

The increase in earnings was due to: (i) the impact of the rate case settlement; (ii) $18 million in FERC-ordered transmission refunds in 2016; (iii) more favourably priced long-term wholesale sales; and (iv) approximately $11 million related to the favourable settlement of FERC-ordered transmission refunds in 2017. The increase was partially offset by: (i) $10 million related to the favourable settlement of Springerville Unit 1 matters in 2016, as discussed above; (ii) an increase in deferred income tax expense as a result of U.S. Tax Reform; (iii) higher operating expenses; and (iv) approximately $3 million of unfavourable foreign exchange associated with the translation of US dollar-denominated earnings.

CENTRAL HUDSON

Financial Highlights			
Years Ended December 31	**2017**	2016	Variance
Average US:CAD Exchange Rate [1]	**1.30**	1.33	(0.03)
Electricity Sales *(GWh)*	**4,891**	5,112	(221)
Gas Volumes *(PJ)*	**22**	24	(2)
Revenue *($ millions)*	**872**	849	23
Earnings *($ millions)*	**70**	70	—

[1] The reporting currency of Central Hudson is the US dollar.

Electricity Sales & Gas Volumes

The decrease in electricity sales and gas volumes was primarily due to cooler temperatures in the summer of 2017. Cooler temperatures resulted in lower average electricity consumption and reduced demand for gas volumes by electric generators, both due to reduced air-conditioning load.

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 mainly due to higher delivery revenue from increases in base electricity and gas rates effective July 1, 2017 and 2016 and the recovery from customers of higher commodity costs. The increase was partially offset by approximately $19 million of unfavourable foreign exchange associated with the translation of US dollar-denominated revenue and lower electricity sales.

Earnings

Earnings were comparable with 2016. A decrease in earnings primarily due to higher operating expenses, the timing of unbilled revenue, which is not subject to the operation of the decoupling mechanism, and approximately $2 million of unfavourable foreign exchange associated with the translation of US dollar-denominated earnings, was offset by the increase in delivery revenue discussed above.

REGULATED UTILITIES - CANADA

Regulated Utilities - Canada earnings for 2017 were $393 million (2016 - $390 million), which represented approximately 38% of the Corporation's total regulated earnings (2016 – 51%). The decrease in percentage of regulated earnings as compared to 2016 was due to the acquisition of ITC in October 2016. Total segment assets were approximately $15.6 billion as at December 31, 2017 (December 31, 2016 - $14.8 billion), which represented approximately 34% of the Corporation's total regulated assets as at December 31, 2017 (December 31, 2016 – 32%).

FORTISBC ENERGY

Financial Highlights Years Ended December 31	**2017**	2016	Variance
Gas Volumes *(PJ)*	**221**	197	24
Revenue *($ millions)*	**1,198**	1,151	47
Earnings *($ millions)*	**154**	151	3

Gas Volumes
The increase in gas volumes was primarily due to customer growth, higher average consumption by residential and commercial customers in 2017 due to colder winter temperatures, and higher gas volumes due to certain transportation customers switching to natural gas compared to alternative fuel sources.

Revenue
The increase in revenue was primarily due to higher gas volumes and a higher commodity cost of natural gas charged to customers, partially offset by an increase in flow-through adjustments owing to customers.

Earnings
The increase in earnings was primarily due to higher allowance for funds used during construction ("AFUDC") associated with the Tilbury liquefied natural gas ("LNG") facility expansion, partially offset by an increase in operating expenses.

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 do not materially affect earnings.

FORTISALBERTA

Financial Highlights Years Ended December 31	**2017**	2016	Variance
Energy Deliveries *(GWh)*	**17,018**	16,788	230
Revenue *($ millions)*	**600**	572	28
Earnings *($ millions)*	**120**	121	(1)

Energy Deliveries
The increase in energy deliveries was primarily due to higher average consumption by residential, commercial and irrigation customers, mainly due to warmer temperatures in the summer of 2017, partially offset by lower oil and gas activity. Growth in the number of residential and commercial customers also contributed to the increase.

Revenue
The increase in revenue was primarily due to an increase in capital tracker revenue, growth in the number of residential and commercial customers, and higher revenue related to the flow through of costs to customers. The increase was partially offset by a decrease in customer rates effective January 1, 2017.

Earnings
Earnings were comparable with 2016. A decrease in earnings primarily due to higher operating costs and finance charges, and lower customer rates, was partially offset by higher capital tracker revenue and customer growth.

FORTISBC ELECTRIC

Financial Highlights Years Ended December 31	**2017**	2016	Variance
Electricity Sales *(GWh)*	**3,305**	3,119	186
Revenue *($ millions)*	**398**	377	21
Earnings *($ millions)*	**55**	54	1

Electricity Sales
The increase in electricity sales was due to higher average consumption primarily due to colder winter temperatures in 2017.

Revenue
The increase in revenue was due to higher electricity sales and an increase in base electricity rates effective January 1, 2017.

Earnings
Earnings were comparable with 2016, with the slight increase in earnings primarily due to higher AFUDC.

EASTERN CANADIAN

Financial Highlights Years Ended December 31	**2017**	2016	Variance
Electricity Sales *(GWh)*	**8,355**	8,374	(19)
Revenue *($ millions)*	**1,062**	1,063	(1)
Earnings *($ millions)*	**64**	64	—

Electricity Sales
The decrease in electricity sales was primarily due to an overall decrease in consumption, partially offset by growth in the number of customers.

Revenue
Revenue was comparable with 2016. A decrease in revenue due to lower electricity sales and the flow through in customer electricity rates of lower energy supply costs was partially offset by an increase in customer rates.

Earnings
Earnings were comparable with 2016. Lower-than-anticipated finance costs were offset by lower electricity sales and approximately $2 million in business development costs related to the Wataynikaneyap Partnership. For details on the Wataynikaneyap Power Project refer to the "Liquidity and Capital Resources - Additional Investment Opportunities" section of this MD&A.

REGULATED UTILITIES - CARIBBEAN

Regulated Utilities - Caribbean earnings for 2017 were $34 million (2016 - $46 million), which represented approximately 3% of the Corporation's total regulated earnings (2016 – 6%). Total segment assets were approximately $1.3 billion as at December 31, 2017 (December 31, 2016 - $1.3 billion), which represented approximately 3% of the Corporation's total regulated assets as at December 31, 2017 (December 31, 2016 – 3%).

Financial Highlights Years Ended December 31	**2017**	2016	Variance
Average US:CAD Exchange Rate [(1)]	**1.30**	1.33	(0.03)
Electricity Sales *(GWh)*	**841**	837	4
Revenue *($ millions)*	**301**	301	—
Earnings *($ millions)*	**34**	46	(12)

(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 due to higher average consumption, partially offset by lower electricity sales due to the impact of Hurricane Irma on Fortis Turks and Caicos.

Revenue
Revenue was comparable with 2016. An increase in revenue due to the flow through in customer electricity rates of higher fuel costs and higher base electricity rates was offset by approximately $6 million of unfavourable foreign exchange associated with the translation of US dollar-denominated revenue and lower electricity sales as a result of the impact of Hurricane Irma.

Earnings
The decrease in earnings was due to lower revenue as a result of the impact of Hurricane Irma, lower equity income from Belize Electricity, and higher finance costs, primarily due to lower capitalized interest.

Fortis Turks and Caicos expects to recover lost revenue, as a result of the impact of Hurricane Irma, through business interruption insurance. Such revenue will be recognized when the insurance claim is settled, which is expected to occur in 2018.

NON-REGULATED

ENERGY INFRASTRUCTURE

Financial Highlights Years Ended December 31	**2017**	2016	Variance
Energy Sales *(GWh)*	**918**	901	17
Revenue *($ millions)*	**226**	193	33
Earnings *($ millions)*	**94**	60	34

Energy Sales
The increase in energy sales was primarily due to increased production in Belize due to higher rainfall in 2017.

Revenue and Earnings
The increase in revenue and earnings was primarily due to higher earnings from Aitken Creek associated with unrealized gains on the mark-to-market of derivatives and a full year of contribution in 2017.

CORPORATE AND OTHER

Financial Highlights Years Ended December 31 *($ millions)*	**2017**	2016	Variance
Revenue	**1**	9	(8)
Operating Expenses	**13**	108	(95)
Depreciation and Amortization	**2**	4	(2)
Other Income, Net	**29**	—	29
Finance Charges	**189**	162	27
Income Tax Recovery	**(69)**	(101)	32
	(105)	(164)	59
Preference Share Dividends	**65**	75	(10)
Corporate and Other Expenses	**(170)**	(239)	69

The decrease in Corporate and Other was primarily due to lower operating expenses, higher other income and lower preference share dividends, partially offset by higher finance charges and a lower income tax recovery.

The decrease in operating expenses was primarily due to the receipt of a $28 million break fee ($24 million net of related transactions costs and tax) associated with the termination of the Waneta Dam purchase agreement in the third quarter of 2017, and acquisition-related expenses totalling $79 million ($62 million after tax) in 2016 associated with ITC. The decrease was partially offset by higher compensation-related expenditures, including higher stock-based compensation as a result of share price appreciation, general inflationary increases and ancillary expenses to support the Corporation's listing on the New York Stock Exchange.

The increase in other income was mainly due to a one-time $21 million unrealized foreign exchange gain on a US dollar-denominated affiliate loan.

The increase in finance charges was primarily due to the acquisition of ITC, including interest expense on debt issued to complete the financing of the acquisition. The increase was partially offset by acquisition-related transaction costs totalling approximately $39 million ($28 million after tax) in 2016 associated with ITC.

The lower income tax recovery was mainly due to deferred income tax expense in 2017 of $48 million, due to U.S. Tax Reform.

The decrease in preference share dividends was due to the redemption of First Preference Shares, Series E in September 2016.

REGULATORY HIGHLIGHTS

The following summarizes the significant regulatory decisions and applications pertaining to the Corporation's regulated utilities for 2017.

ITC

ROE Complaints
Two third-party complaints are pending before FERC requesting that the MISO regional base ROE of 12.38% for MISO transmission owners, including some of ITC's operating subsidiaries, be found to no longer be just or reasonable. The complaints cover two consecutive 15-month periods from November 2013 through February 2015 (the "Initial Refund Period" or "Initial Complaint") and February 2015 through May 2016 (the "Second Refund Period" or "Second Complaint"). The FERC orders on the complaints will also set the ROE that will be in effect prospectively from the date that the FERC orders are issued. In September 2016 FERC issued an order setting the base ROE for the Initial Refund Period at 10.32%, with a maximum ROE of 11.35%. These rates apply prospectively from September 2016 until a new approved rate is established for the Second Refund Period. The MISO transmission owners have sought rehearing of the September 2016 order.

In June 2016 the presiding Administrative Law Judge issued an initial decision on the Second Complaint, recommending a base ROE of 9.70%, with a maximum ROE of 10.68%. This initial decision is a non-binding recommendation to FERC and FERC has yet to issue its order on the Second Complaint. In September 2017 certain MISO transmission owners filed a motion for FERC to dismiss the Second Complaint. If the Second Complaint is not dismissed, it is expected that FERC will establish a new going-forward base ROE and range of reasonableness, which will also be used to calculate the refund liability for the Second Refund Period.

As at December 31, 2017, the estimated range of refunds for the Second Refund Period was between US$106 million and US$145 million and ITC has recognized an aggregate estimated regulatory liability of $182 million (US$145 million). The total estimated refund for the Initial Complaint was $158 million (US$118 million), including interest, as at December 31, 2016, which was paid in 2017.

The estimated regulatory liabilities were accrued by ITC before its acquisition by Fortis. There is uncertainty regarding the final outcome of the Initial and Second Complaints and the timing of the completion of these matters. This is due, in part, to an April 2017 court decision requiring FERC to further justify the methodology used to establish new ROEs. It is possible that the outcome of these matters could differ materially from the estimated range of refunds.

UNS Energy

General Rate Application
In February 2017 the ACC issued a rate order for new rates for TEP that took effect February 27, 2017 ("2017 Rate Order"). Provisions of the 2017 Rate Order include: (i) an increase in non-fuel base revenue of approximately $108 million (US$81.5 million), including approximately $20 million (US$15 million) of operating costs related to the 50.5% undivided interest in Unit 1 of Springerville Generating Station purchased by TEP in September 2016; (ii) a 7.04% return on original cost rate base, including a cost of equity of 9.75% and an embedded cost of long-term debt of 4.32%; (iii) a common equity component of capital structure of approximately 50%; and (iv) the adoption of proposed depreciation rates which reflect a reduction in the depreciable life for Unit 1 of San Juan Generating Station. Certain aspects of TEP's rate application, including net metering and rate design for new distributed generation customers, have been deferred to a second phase of TEP's rate case, which is currently expected to be completed in the first half of 2018. TEP cannot predict the outcome of these proceedings.

FERC Order
In 2015 and 2016 TEP reported to FERC that it had not filed on a timely basis certain FERC jurisdictional agreements and, at that time, TEP made compliance filings, including the filing of several TEP transmission service agreements, the majority of which were entered into before the acquisition of UNS Energy by Fortis in 2014, that contained certain deviations from TEP's standard form of service agreement. In 2016 FERC issued orders relating to the late-filed transmission service agreements, which directed TEP to issue time value refunds to the counterparties of the agreements. In 2016 TEP accrued time value refunds of $29 million, of which $22 million had been paid, and as at December 31, 2016 $7 million was accrued related to time-value refunds.

In June 2016, to preserve its rights, TEP petitioned the District of Columbia Circuit Court of Appeals to review the refund order. In January 2017 TEP and one of the counterparties to the late-filed transmission service agreements entered into a settlement regarding the time value refunds. Under the settlement, in January 2017, the counterparty paid TEP $11 million and TEP dismissed its appeal with prejudice.

In May 2017 FERC informed TEP that no further enforcement actions were necessary regarding TEP's transmission refunds and closed the related investigation. As a result, TEP reversed the remaining $7 million provision related to potential time-value refunds.

Central Hudson

General Rate Application
In July 2017 Central Hudson filed a rate case with the New York Public Service Commission ("PSC") requesting an increase in electric and natural gas rates of $55 million (US$43 million) and $23 million (US$18 million), respectively. Included in the rate case was a request to increase Central Hudson's allowed ROE to 9.5% from 9.0% and the equity component of its capital structure to 50% from 48%. An order from the PSC is expected in August 2018 with the new rates to become effective no later than September 1, 2018, with a provision allowing the recovery of revenue as if approved rates went into effect July 1, 2018.

FortisAlberta

Generic Cost of Capital
In July 2017 the AUC established a proceeding to determine the ROE and capital structure for 2018, 2019 and 2020. The proceeding commenced in October 2017, with an oral hearing expected to commence in March 2018. The ROE and capital structure approved for 2017 will remain in effect on an interim basis pending the finalization of this proceeding. A decision is expected in the third quarter of 2018.

Next Generation Performance-Based Rate-Setting Proceeding
FortisAlberta filed a rebasing application in April 2017 to establish the going-in revenue requirement and an incremental capital funding mechanism for the second PBR term, being the five-year period from 2018 through 2022. The going-in revenue requirement will be used to determine the going-in rates upon which the PBR formula will be applied to establish distribution rates for 2018.

In February 2018 the AUC issued a decision on the rebasing application refining the manner in which distribution rates will be determined during the second PBR term. FortisAlberta has been directed to file a second rebasing compliance filing by March 1, 2018 and to use the approved 2017 PBR rates on an interim basis for 2018. The final 2018 PBR rates are expected to be effective April 1, 2018.

Significant Regulatory Proceedings

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

Regulated Utility	Application / Proceeding	Filing Date	Expected Decision
ITC	MISO Base ROE Complaints	Not applicable	To be determined
Central Hudson	General Rate Application	July 2017	August 2018

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2017 and December 31, 2016.

Significant Changes in the Consolidated Balance Sheets between December 31, 2017 and December 31, 2016

Balance Sheet Account	**Increase / (Decrease)** *($ millions)*	**Explanation**
Regulatory assets - current and long-term	112	The increase was primarily due to the reclassification of generation assets at UNS Energy from property, plant and equipment, partially offset by the impact of foreign exchange associated with the translation of US dollar-denominated regulatory assets.
Property, plant and equipment, net	331	The increase was mainly due to capital expenditures, partially offset by depreciation, the impact of foreign exchange on the translation of US dollar-denominated property, plant and equipment, the reclassification of a reserve from regulatory liabilities at UNS Energy and the reclassification of the net book value of generation assets, planned for early retirement, to regulatory assets at UNS Energy.
Goodwill	(720)	The decrease was mainly due to the impact of foreign exchange associated with the translation of US dollar-denominated goodwill.
Short-term borrowings	(946)	The decrease was mainly due to the repayment of the Corporation's equity bridge credit facility, which was used to finance a portion of the acquisition of ITC. The decrease was also due to the repayment of commercial paper at ITC and short-term borrowings at other regulated entities using proceeds from the issuance of long-term debt.
Regulatory liabilities - current and long-term	1,263	The increase was primarily due to a one-time remeasurement of net deferred income tax liabilities at the Corporation's US subsidiaries due to U.S. Tax Reform resulting in the recognition of a regulatory liability of $1.5 billion. The increase was partially offset by a reduction in regulatory liabilities at ITC associated with the refund payment associated with the Initial Complaint, the reclassification of a reserve to property, plant and equipment at UNS Energy, and the impact of foreign exchange associated with the translation of US dollar-denominated regulatory liabilities.
Long-term debt (including current portion)	328	The increase was mainly due to the issuance of senior notes at ITC used primarily to repay maturing long-term debt and borrowings under its commercial paper program. The increase was also due to debt issuances at other regulated utilities, partially offset by the impact of foreign exchange associated with the translation of US dollar-denominated debt and regularly scheduled debt repayments.
Deferred income tax liabilities	(965)	The decrease was primarily due to a one-time remeasurement of net deferred income tax liabilities at the Corporation's U.S. subsidiaries due to U.S. Tax Reform totalling $1.3 billion and the impact of foreign exchange associated with the translation of US dollar-denominated deferred income tax liabilities, partially offset by timing differences associated with capital expenditures at the regulated utilities.
Shareholders' equity (before non-controlling interests)	406	The increase was primarily due to: (i) the issuance of $500 million of common shares; (ii) net earnings attributable to common equity shareholders for 2017, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment and other share plans. The increase was partially offset by a decrease 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.
Non-controlling interests	(107)	The decrease was mainly due to the impact of foreign exchange associated with the translation of US dollar-denominated non-controlling interests.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CONSOLIDATED CASH FLOWS

The table below outlines the Corporation's sources and uses of cash in 2017 compared to 2016, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows Years ended December 31 *($ millions)*	**2017**	2016	Variance
Cash, Beginning of Year	**269**	242	27
Cash Provided by (Used in):			
Operating Activities	**2,756**	1,884	872
Investing Activities	**(3,025)**	(6,891)	3,866
Financing Activities	**339**	5,050	(4,711)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(12)**	(16)	4
Cash, End of Year	**327**	269	58

Operating Activities: Cash flow from operating activities in 2017 was $872 million higher than in 2016. The increase was primarily due to higher cash earnings, driven by ITC and UNS Energy, and the Corporation's acquisition-related transaction costs in 2016. Favourable changes in long-term regulatory deferrals were offset by unfavourable changes in working capital.

Investing Activities: Cash used in investing activities in 2017 was $3,866 million lower than in 2016. The decrease was due to the acquisition of ITC in October 2016 for net cash consideration of approximately $4.5 billion and the acquisition of Aitken Creek in April 2016 for a net purchase price of $318 million, partially offset by an increase in capital expenditures. The increase in capital expenditures was driven by capital spending at ITC and higher capital spending at most of the Corporation's regulated utilities.

Financing Activities: Cash provided by financing activities in 2017 was $4,711 million lower than in 2016. The decrease was primarily due to financing activities associated with the acquisition of ITC in October 2016. The net cash consideration associated with the acquisition of ITC was financed using: (i) net proceeds from the issuance of US$2.0 billion ($2.6 billion) unsecured notes in October 2016; (ii) net proceeds from GIC's US$1.228 billion ($1.6 billion) minority investment, which includes a shareholder note of US$199 million ($263 million); and (iii) drawings of approximately $535 million (US$404 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility.

In March 2017 approximately 12.2 million common shares of Fortis were issued to an institutional investor for proceeds of $500 million. The proceeds were used to repay short-term borrowings.

In addition to the impact of financing activities associated with ITC, higher repayments of long-term debt, higher net repayments under committed credit facilities and changes in short-term borrowings also contributed to the decrease in cash provided by financing activities. The decrease was partially offset by higher proceeds from the issuance of long-term debt at the Corporation's regulated utilities, driven by ITC.

In September 2016 the Corporation redeemed all of the First Preference Share, Series E for $200 million.

Proceeds from long-term debt, net of issue costs, for 2017 and 2016 are summarized in the following table.

Proceeds from Long-Term Debt, Net of Issue Costs Years ended December 31 ($ millions)	**2017**	2016	Variance
ITC [(1)]	**1,863**	264	1,599
Central Hudson [(2)]	**74**	68	6
FortisBC Energy [(3)]	**173**	446	(273)
FortisAlberta [(4)]	**199**	149	50
FortisBC Electric [(5)]	**74**	—	74
Eastern Canadian [(6)] [(7)]	**75**	40	35
Caribbean [(8)] [(9)]	**80**	65	15
Corporate [(10)]	**—**	3,104	(3,104)
Total	**2,538**	4,136	(1,598)

(1) In March 2017 ITC entered into 1-year and 2-year unsecured term loan credit agreements at floating interest rates of a one-month LIBOR plus a spread of 0.90% and 0.65%, respectively. Borrowings under the term loan credit agreements were US$200 million and US$50 million, respectively, representing the maximum amounts available under the agreements. The net proceeds from these borrowings were used to repay credit facility borrowings and for general corporate purposes. The US$200 million term loan was subsequently repaid using long-term debt issued in November 2017. In April 2017 ITC issued 30-year US$200 million secured first mortgage bonds at 4.16%. The net proceeds from the issuance were used to repay credit facility borrowings and for general corporate purposes. In November 2017 ITC issued 5-year US$500 million unsecured notes at 2.70% and 10-year US$500 million unsecured notes at 3.35%. The net proceeds from the issuances were used to repay long-term debt, including borrowings under the term loan as discussed above, to repay short-term borrowings, and for general corporate purposes. In October 2016 a 12-year shareholder note of US$199 million at 6.00% was issued to an affiliate of GIC as part of its minority investment in ITC. The proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC.

(2) In August 2017 Central Hudson issued 30-year US$30 million unsecured notes at 4.05% and 40-year US$30 million unsecured notes at 4.20%. The net proceeds from the issuances were used to repay long-term debt and for general corporate purposes. In June 2016 Central Hudson issued 4-year US$24 million unsecured notes at 2.16%. The net proceeds were used to finance capital expenditures and for general corporate purposes. In October 2016 Central Hudson issued US$30 million of unsecured notes in a dual tranche of 10-year US$10 million unsecured notes at 2.56% and 30-year US$20 million unsecured debentures at 3.63%. The net proceeds were used to finance capital expenditures and for general corporate purposes.

(3) In October 2017 FortisBC Energy issued 30-year $175 million unsecured debentures at 3.69%. The net proceeds from the issuance were used to repay short-term borrowings and to finance capital expenditures. In April 2016 FortisBC Energy issued $300 million of unsecured debentures in a dual tranche of 10-year $150 million unsecured debentures at 2.58% and 30-year $150 million unsecured debentures at 3.67%. In December 2016 FortisBC Energy issued 30-year $150 million unsecured debentures at 3.78%. The net proceeds from the issuances were used to repay short-term borrowings and to finance capital expenditures.

(4) In September 2017 FortisAlberta issued 30-year $200 million unsecured debentures at 3.67%. The net proceeds from the issuance were used to repay credit facility borrowings, to finance capital expenditures and for general corporate purposes. In September 2016 FortisAlberta issued 30-year $150 million unsecured debentures at 3.34%. The net proceeds were used to repay credit facility borrowings, to finance capital expenditures and for general corporate purposes.

(5) In December 2017 FortisBC Electric issued 32-year $75 million unsecured debentures at 3.62%. The net proceeds from the issuance were used to repay short-term borrowings.

(6) In June 2017 Newfoundland Power issued 40-year $75 million first mortgage sinking fund bonds at 3.815%. The net proceeds from the issuance were used to repay credit facility borrowings and for general corporate purposes.

(7) In August 2016 Maritime Electric issued 40-year $40 million secured first mortgage bonds at 3.657%. The net proceeds were primarily used to repay long-term debt and short-term borrowings.

(8) In March and May 2017, Caribbean Utilities issued US$60 million of unsecured notes in a dual tranche of 15-year US$40 million at 3.90% and 30-year US$20 million at 4.64%, respectively. The net proceeds from the issuances were used to finance capital expenditures and repay short-term borrowings.

(9) In May and September 2016, Fortis Turks and Caicos issued 15-year US$45 million unsecured notes in a dual tranche of US$22.5 million at 5.14% and 5.29%, respectively. In July 2016 Fortis Turks and Caicos issued 15-year US$5 million unsecured bonds at 5.14%. The net proceeds were used to finance capital expenditures and for general corporate purposes.

(10) In October 2016 the Corporation issued 5-year US$500 million unsecured notes at 2.100% and 10-year US$1.5 billion unsecured notes at 3.055%. The net proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC. In December 2016 the Corporation issued 7-year $500 million unsecured notes at 2.85%. The net proceeds were used to repay credit facility borrowings, mainly related to the financing of the acquisition of Aitken Creek in April 2016 and the redemption of First Preference Shares, Series E in September 2016, and for general corporate purposes.

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.

Common share dividends paid in 2017 totalled $419 million, net of $253 million of dividends reinvested, compared to $316 million, net of $162 million of dividends reinvested, paid in 2016. 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 $1.625 in 2017 compared to $1.525 in 2016. The weighted average number of common shares outstanding was 415.5 million for 2017 compared to 308.9 million for 2016.

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, 2017, are outlined in the following table.

Contractual Obligations **As at December 31, 2017** *($ millions)*	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Long-term debt	**21,535**	705	282	673	1,219	1,060	17,596
Interest obligations on long-term debt	**14,575**	892	878	858	837	792	10,318
Capital lease and finance obligations *(1)*	**2,314**	90	74	73	78	49	1,950
Power purchase obligations *(2)*	**2,240**	275	157	126	118	117	1,447
Renewable power purchase obligations *(3)*	**1,428**	93	92	92	92	91	968
Gas purchase obligations *(4)*	**1,085**	278	201	189	147	112	158
Long-term contracts - UNS Energy *(5)*	**910**	157	158	125	79	50	341
ITC easement agreement *(6)*	**413**	13	13	13	13	13	348
Renewable energy credit purchase agreements *(7)*	**125**	20	13	11	10	10	61
Debt Collection Agreement *(8)*	**122**	3	3	3	3	3	107
Purchase of Springerville Common Facilities *(9)*	**85**	—	—	—	85	—	—
Waneta Partnership promissory note	**72**	—	—	72	—	—	—
Operating lease obligations	**53**	11	9	7	4	4	18
Joint-use asset and shared service agreements	**52**	3	3	3	3	3	37
Other *(10)*	**462**	97	53	71	31	32	178
Total	**45,471**	2,637	1,936	2,316	2,719	2,336	33,527

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

(2) Power purchase obligations include various power purchase contracts held by the Corporation's regulated utilities, of which the most significant contracts are described below.

FortisOntario: Power purchase obligations for FortisOntario, totalling $692 million as at December 31, 2017, include a contract with Hydro-Quebec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through to December 2030. This contract will replace FortisOntario's existing long-term take-or-pay contracts with Hydro-Quebec to supply 145 MW of capacity expiring in 2019.

FortisBC Energy: FortisBC Energy is party to an electricity supply agreement with BC Hydro for the purchase of electricity supply to the Tilbury LNG facility expansion, with purchase obligations totalling $482 million as at December 31, 2017.

FortisBC Electric: Power purchase obligations for FortisBC Electric, totalling $333 million as at December 31, 2017, 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. FortisBC Electric is also party to the Waneta Expansion Capacity Agreement ("WECA"), allowing it to purchase 234 MW of capacity per month, on average, for 40 years, effective April 2015, as approved by the British Columbia Utilities Commission ("BCUC"). Amounts associated with the WECA have not been included in the Contractual Obligations table as they will be paid by FortisBC Electric to a related party.

Maritime Electric: Maritime Electric's power purchase obligations include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power"). 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, and as at December 31, 2017, had commitments of $511 million under this arrangement.

(3) TEP and UNS Electric are party to long-term renewable PPAs that require them to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the Contractual Obligations table includes estimated future payments. These agreements have various expiry dates from 2027 through 2036.

(4) Certain of the Corporation's subsidiaries, mainly FortisBC Energy, 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, 2017.

(5) UNS Energy enters 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. 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.

(6) ITC is party to an easement agreement with Consumers Energy, the primary customer of METC, which provides the Company with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 additional 50-year renewals thereafter.

(7) UNS Energy and Central Hudson are party to renewable energy credit purchase agreements, mainly for the purchase of environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are made in contractually agreed-upon intervals based on metered renewable energy production.

(8) Maritime Electric is party to a debt collection agreement with the PEI Energy Corporation for the initial capital cost of the submarine cables and associated parts of the New Brunswick Transmission system interconnection. The agreement expires in February 2056. Payments under the agreement will be collected from customers in future rates.

(9) UNS Energy has an obligation to purchase an undivided 32.2% interest in the Springerville Common Facilities if the related two leases are not renewed.

(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, land easements, asset retirement obligations, and defined benefit pension plan funding 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 $3.2 billion for 2018. Over the five year period from 2018 through 2022, the Corporation's consolidated capital expenditure program is expected to be approximately $14.5 billion, which has not been included in the Contractual Obligations table.

Other: CH Energy Group is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion. CH Energy Group's maximum commitment is US$182 million, for which it has issued a parental guarantee. As at December 31, 2017, there was no obligation under this guarantee.

As at December 31, 2017 FHI had $80 million (December 31, 2016 - $77 million) of parental guarantees outstanding to support the storage optimization activities of Aitken Creek.

The Corporation's regulatory liabilities of $3,446 million as at December 31, 2017 have been excluded from the Contractual Obligations table, as the final timing of settlement of such liabilities is subject to further regulatory determination or the settlement periods are not currently known.

CAPITAL STRUCTURE

The Corporation's principal business 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 that will enable it to maintain 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 their customer rates.

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

Capital Structure As at December 31	**2017**		2016	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [(1)]	**21,739**	**59.2**	22,490	60.6
Preference shares	**1,623**	**4.4**	1,623	4.4
Common shareholders' equity	**13,380**	**36.4**	12,974	35.0
Total	**36,742**	**100.0**	37,087	100.0

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

Including amounts related to non-controlling interests, the Corporation's capital structure as at December 31, 2017 was 56.5% total debt and capital lease and finance obligations (net of cash), 4.2% preference shares, 34.8% common shareholders' equity and 4.5% non-controlling interests (December 31, 2016 - 57.8% total debt and capital lease and finance obligations (net of cash), 4.2% preference shares, 33.3% common shareholders' equity and 4.7% non-controlling interests).

The improvement in the Corporation's capital structure was primarily due to a decrease in total debt and an increase in common shareholders' equity as a result of: (i) the decrease in debt due to the impact of foreign exchange on the translation of US dollar-denominated debt, scheduled debt repayments, and net repayments under committed credit facilities, partially offset by the issuance of new long-term debt in support of energy infrastructure investment; (ii) the issuance of $500 million of common shares in March 2017, used for the repayment of short-term borrowings; (iii) the issuance of common shares under the Corporation's dividend reinvestment and other share plans; and (iv) net earnings attributable to common equity shareholders for 2017, less dividends declared on common shares. The increase in common shareholders' equity was partially offset by a decrease 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.

CREDIT RATINGS

As at December 31, 2017, the Corporation's credit ratings were as follows.

Rating Agency	Credit Rating	Type of Rating	Outlook
Standard & Poor's ("S&P")	A-	Corporate	Stable
	BBB+	Unsecured debt	
DBRS	BBB (high)	Corporate	Stable
	BBB (high)	Unsecured debt	
Moody's Investor Service ("Moody's")	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

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 the level of debt at the holding company. In May 2017 S&P and DBRS affirmed the Corporation's long-term corporate and unsecured debt credit ratings, and in September 2017 Moody's affirmed the Corporation's long-term issuer and unsecured debt credit ratings.

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 $440 million in maintenance and repairs was expensed in 2017 compared to approximately $330 million in 2016. The increase was largely due to a full year of expense for ITC in 2017.

Consolidated capital expenditures for 2017 were approximately $3.0 billion. A breakdown of these capital expenditures by segment and asset category for 2017 is provided in the following table.

Consolidated Capital Expenditures (1)
Year Ended December 31, 2017
($ millions)

	Regulated Utilities										
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean	**Total Regulated Utilities**	**Non-Regulated** (2)	**Total**
Generation	—	231	1	—	—	4	8	45	**289**	**6**	**295**
Transmission	883	43	35	188	—	15	20	16	**1,200**	**—**	**1,200**
Distribution	—	181	138	156	342	43	110	67	**1,037**	**—**	**1,037**
Facilities, equipment, vehicles and other (3)	66	29	26	79	53	34	9	15	**311**	**15**	**326**
Information technology	33	50	20	23	19	9	9	3	**166**	**—**	**166**
Total	982	534	220	446	414	105	156	146	**3,003**	**21**	**3,024**

(1) Represents cash payments to construct property, plant and equipment and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC.
(2) Includes Energy Infrastructure and Corporate and Other segments
(3) Includes capital expenditures associated with the Tilbury LNG facility 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. Consolidated capital expenditures of $3.0 billion for 2017 were consistent with the 2017 forecast of $3.0 billion, as disclosed in the MD&A for the year ended December 31, 2016.

Consolidated capital expenditures for 2018 are expected to be approximately $3.2 billion. A breakdown of forecast consolidated capital expenditures by segment and asset category for 2018 is provided in the following table.

Forecast Consolidated Capital Expenditures (1)
Year Ending December 31, 2018
($ millions)

	Regulated Utilities										
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean	**Total Regulated Utilities**	**Non-Regulated** (2)	**Total**
Generation	—	251	3	—	—	5	13	85	**357**	**26**	**383**
Transmission	814	98	31	228	—	16	16	28	**1,231**	**—**	**1,231**
Distribution	—	201	175	138	305	40	104	27	**990**	**—**	**990**
Facilities, equipment, vehicles and other (3)	25	70	30	72	74	37	12	4	**324**	**23**	**347**
Information technology	24	66	36	24	28	6	10	8	**202**	**—**	**202**
Total	863	686	275	462	407	104	155	152	**3,104**	**49**	**3,153**

(1) Represents forecast cash payments to construct property, plant and equipment 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 2018 are based on a forecast exchange rate of US$1.00=CAD$1.28. Based on the closing foreign exchange rate on December 31, 2017 of US$1.00=CAD$1.25 forecast capital expenditures for 2018 would be approximately $3.1 billion.
(2) Includes Energy Infrastructure and Corporate and Other segments
(3) Includes forecast capital expenditures associated with the Tilbury LNG facility expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

The percentage breakdown of 2017 actual and 2018 forecast consolidated capital expenditures among growth, sustaining and other is as follows.

Consolidated Capital Expenditures Year Ending December 31 *(%)*	**Actual** **2017**	Forecast 2018
Growth *(1)*	**34**	30
Sustaining *(2)*	**51**	55
Other *(3)*	**15**	15
Total	**100**	100

(1) Capital expenditures to connect new customers and infrastructure upgrades required to meet customer and associated load growth, including capital expenditures associated with the Tilbury LNG facility 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, transmission and distribution assets
(3) Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period from 2018 through 2022 ("five-year capital program"), consolidated capital expenditures are expected to be approximately $14.5 billion, $1.5 billion higher than $13 billion previously forecast for the period from 2017 through 2021, as disclosed in the MD&A for the year ended December 31, 2016. The increase in the five-year capital program is the result of the Corporation's sustainable organic growth platform and reflects increased investment mainly at FortisBC Energy and UNS Energy. The low-risk, highly executable five-year capital program contains only a small number of major projects that individually exceed $150 million.

The approximate breakdown of the capital spending expected to be incurred is as follows: 55% at U.S. Regulated Utilities, including 25% at ITC; 40% at Canadian Regulated Utilities; 4% at Caribbean Regulated 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: 34% to meet customer growth, 53% for sustaining capital expenditures, and 13% for facilities, equipment, vehicles, information technology and other assets.

Actual 2017 and forecast 2018 midyear rate base for the Corporation's regulated utilities and the Waneta Expansion is provided in the following table.

Midyear Rate Base *($ billions)*	**Actual** **2017**	Forecast 2018
ITC *(1)*	**7.2**	7.7
UNS Energy *(1)*	**4.6**	4.8
Central Hudson *(1)*	**1.6**	1.7
FortisBC Energy	**4.1**	4.3
FortisAlberta	**3.1**	3.4
FortisBC Electric	**1.3**	1.3
Eastern Canadian	**1.7**	1.8
Caribbean *(1)*	**1.0**	1.0
Waneta Expansion	**0.8**	0.8
Total	**25.4**	26.8

(1) Actual midyear rate base for 2017 is based on the actual average exchange rate of US$1.00=CAD$1.30 and forecast midyear rate base for 2018 is based on a forecast exchange rate of US$1.00=CAD$1.28. Based on the closing foreign exchange rate on December 31, 2017 of US$1.00=CAD$1.25 forecast midyear rate base for 2018 would be approximately $26.4 billion.

The most significant capital projects that are included in the Corporation's consolidated capital expenditures for 2017 and over the five-year period from 2018 through 2022 are summarized in the table below.

Significant Capital Projects [1] *($ millions)* **Company**	**Nature of Project**	Pre-2017	**Actual 2017**	Forecast 2018	Forecast 2019 - 2022	Expected Year of Completion
ITC [2] [3]	Multi-Value Regional Transmission Projects ("MVPs")	57	**313**	169	194	Post-2022
	34.5 to 69 kilovolt ("kV") Conversion Project	11	**75**	111	369	Post-2022
UNS Energy [3]	Flexible Generation - Reciprocating Engines	—	**30**	150	45	2019-2020
	Gila River Generating Station Unit 2	—	**—**	—	211	2019
FortisBC Energy	Tilbury LNG Facility Expansion	406	**44**	12	8	2018
	Lower Mainland System Upgrade [4]	43	**145**	177	55	2019
	Eagle Mountain Woodfibre Gas Pipeline Project [5]	—	**—**	—	350	2021/2022
	Pipeline Integrity Management Program	—	**—**	—	312	Post-2022

(1) Represents property, plant and equipment and intangible asset expenditures, including both the capitalized debt and equity components of AFUDC, where applicable. Significant capital projects are identified as those with a total project cost of $150 million or greater and exclude ongoing capital maintenance projects.
(2) Capital expenditures prior to 2017 are from the date of acquisition of October 14, 2016.
(3) Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CAD$1.28 for 2018 through 2022.
(4) FortisBC Energy is currently in the process of reassessing costs following completion of detailed engineering work and evaluation of construction bids and other costs.
(5) Net of forecast customer contributions.

The MVPs at ITC consist of four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. Approximately $370 million (US$284 million) was invested in the MVPs from the date of acquisition of ITC, and an additional $169 million (US$132 million) is expected to be spent in 2018. The projects are in various stages of construction with in-service dates expected to range from 2018 through post 2022.

The 34.5 to 69kV Conversion Project at ITC consists of multiple capital initiatives designed to construct and rebuild new 69-kV lines, with in-service dates ranging from 2018 to post 2022. Approximately $480 million (US$376 million) is expected to be invested in this project over the five-year period through 2022.

The 200 MW flexible generation resources at UNS Energy will consist of 10 natural gas-fired reciprocating engines. The engines will replace aging, less efficient steam turbines and provide ramping and peaking capability, facilitating the addition of renewable generating sources to the grid. The total cost of the program is estimated at $225 million (US$175 million) with expected in-service dates between 2019 and 2020.

The 550 MW natural gas-fired Gila River Generating Station Unit 2 at UNS Energy will assist with the replacement of retiring coal-fired generation facilities. The total cost of the project is estimated to be $211 million (US$165 million) and includes an initial power purchase agreement with a purchase option expected to be exercised in late 2019.

Approximately $450 million, including AFUDC and development costs, has been invested in the Tilbury LNG facility expansion, in British Columbia, to the end of 2017. The total cost of the project is estimated at approximately $470 million, including approximately $70 million of AFUDC and development costs. During 2018 FortisBC Energy will be reviewing modifications to the facility before restarting the commissioning process on the facility, which was interrupted in the third quarter of 2017. The LNG storage tank and a new liquefier are both expected to be in service during the second half of 2018.

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 Coastal Transmission System ("CTS") phase, which is intended to increase security of supply; and (ii) the Lower Mainland Intermediate Pressure System Upgrade ("LMIPSU") project phase, which is focused on addressing pipeline condition issues. Construction activities for the CTS project are complete, and the new pipelines have been commissioned and are in-service. FortisBC Energy is currently in the process of reassessing costs for the LMIPSU project phase following completion of detailed engineering work and evaluation of construction bids and other costs. The project is expected to be constructed during 2018 and 2019. The total capital cost of both phases of the Lower Mainland System Upgrade is estimated to be approximately $420 million, with approximately $177 million forecast to be spent 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 Eagle Mountain Woodfibre Gas Pipeline Project at FortisBC Energy is a pipeline expansion at a proposed LNG site in Squamish, British Columbia. The current estimate of FortisBC Energy's investment in the project may be updated for final scoping, detailed construction estimates and scheduling, and final determination of customer capital contributions. FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting this project from further regulatory approval by the BCUC. Woodfibre LNG Limited has obtained an export license from the National Energy Board ("NEB"), which was recently extended from 25 to 40 years, and received environmental assessment approvals from the Squamish First Nation, the British Columbia Environmental Assessment Office and the Canadian Environmental Assessment Agency. FortisBC Energy also received environmental assessment approval from the Squamish First Nation and provincial environmental assessment approval in 2016. In November 2016 Woodfibre LNG Limited announced the approval from its parent company, Pacific Oil & Gas Limited, which is part of the Singapore-based RGE group of companies, of the funds necessary to proceed with the project. Given the increased certainty with the number of project approvals received and the level of planning, engineering and expenditures completed by Woodfibre LNG Limited to date, the Eagle Mountain Woodfibre Gas Pipeline Project has been included in the five-year capital program. FortisBC Energy's anticipated capital expenditures, net of forecast customer contributions, is $350 million and remains contingent on Woodfibre LNG Limited making a final investment decision. Should the project proceed, it is not expected to be in service before 2021.

The Pipeline Integrity Management Program at FortisBC Energy is a multi-year program focused on improving pipeline safety and the integrity of the high-pressure transmission system, including pipeline modifications and looping. The total capital cost of the program through 2022 is expected to be $312 million.

ADDITIONAL INVESTMENT OPPORTUNITIES

Management is pursuing additional investment opportunities within existing service territories. These additional investment opportunities, as discussed below, are not included in the Corporation's five-year capital program.

FortisOntario - Wataynikaneyap Power Project
The Wataynikaneyap Power Project continues to advance in Ontario. Consisting of a partnership between 22 First Nation communities and FortisOntario, the project's mandate is to connect remote First Nation communities to the electricity grid in Ontario through the development of new transmission lines. In 2016 the Government of Ontario designated Wataynikaneyap Power as the licensed transmission company to complete this project. Fortis reached an agreement with Renewable Energy Systems Canada in December 2016 to acquire its ownership interest in the Wataynikaneyap Partnership. The transaction was approved by the Ontario Energy Board ("OEB") and closed in March 2017. As a result, Fortis' ownership interest in the Wataynikaneyap Partnership has increased to 49%, with the remaining 51% ownership interest held by the 22 First Nation communities. The total estimated capital cost for the project, subject to final cost estimation, is approximately $1.35 billion and is expected to contribute to significant savings for the First Nation communities and result in a significant reduction in greenhouse gas emissions. In March 2017 the project reached a significant milestone with the approval by the OEB of a deferral account to recover development costs incurred between November 2010 and the commencement of construction. In August 2017 the federal government announced it will fully fund, up to $60 million, to connect the Pikangikum First Nation to Ontario's power grid, a component of the larger Wataynikaneyap Power Project. In addition to environmental assessments underway, other regulatory approvals are currently being sought and the next regulatory milestone will be the preparation and filing of the leave to construct with the OEB, which is expected in the first quarter of 2018. Construction of the larger Wataynikaneyap Power Project will commence pending the receipt of permits, approvals and a funding agreement between the federal and provincial governments, which are in progress.

ITC - Lake Erie Connector
The Lake Erie Connector is a proposed 1,000 MW, bi-directional, high-voltage direct current underwater transmission line that would provide the first direct link between the markets of the Ontario Independent Electricity System Operator and PJM Interconnection, LLC. The project would enable transmission customers to more efficiently access energy, capacity and renewable energy credit opportunities in both markets.

In January 2017 ITC received approval of a Presidential Permit from the U.S. Department of Energy for the Lake Erie Connector transmission line, which is a required approval for international border-crossing projects. Also in January 2017, ITC received a report from Canada's NEB recommending the issuance of a Certificate of Public Convenience and Necessity ("CPCN") with prescribed conditions for the transmission line. In May 2017 ITC completed the major permit process in Pennsylvania upon receipt of two required permits from the Pennsylvania Department of Environmental Protection. In June 2017 ITC received approval from Canada's Governor in Council and the CPCN was issued by the NEB. In October 2017 ITC received permits from the U.S. Army Corps of Engineers, which completes the project's major application process in the United States and Canada. The project continues to advance through regulatory, operational, and economic milestones. Ongoing activities include completing project cost refinement and securing favourable transmission service agreements with prospective counterparties. Pending achievement of key milestones, the expected in-service date for the project is late 2021, or three years from the commencement of construction.

FortisBC Energy - LNG
FortisBC Energy continues to pursue additional LNG infrastructure investment opportunities in British Columbia, including further expansion of the Tilbury LNG facility, which is uniquely positioned to meet customer demand for clean-burning natural gas. The site is scalable and can accommodate additional storage and liquefaction equipment, and is relatively close to international shipping lanes. Fortis continues to have discussions with a number of potential export customers.

Other Opportunities
Other capital investments opportunities, above the five-year capital program, include, but are not limited to: incremental regulated transmission investment opportunities and energy storage and contracted transmission projects at ITC; renewable energy investments, energy storage projects, grid modernization, infrastructure resiliency, and transmission investments at UNS Energy; and further gas infrastructure opportunities at FortisBC Energy.

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, long-term debt offerings and equity injections from Fortis.

The Corporation's ability to service its debt obligations and pay dividends on its common and preference shares is dependent on the financial results of the 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. These include restrictions by certain regulators limiting the amount of annual dividends and restrictions by certain lenders limiting the amount of debt to total capitalization at the subsidiaries. In addition, there are practical limitations on using the net assets of each of the Corporation's regulated subsidiaries to pay dividends based on management's intent to maintain the regulator-approved capital structures for each of its regulated subsidiaries. The Corporation does not expect that maintaining the targeted capital structures of its regulated subsidiaries will have an impact on its ability to pay dividends in the foreseeable future.

Cash required of Fortis to support subsidiary capital expenditure programs 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.

In December 2017 FortisAlberta filed a short-form base shelf prospectus, under which the Company may issue debentures in an aggregate principal amount of up to $500 million during the 25-month life of the base shelf prospectus.

In October 2017 FortisBC Energy filed a short-form base shelf prospectus, under which the Company may issue debentures in an aggregate principal amount of up to $650 million during the 25-month life of the base shelf prospectus. Also in October, the Company issued $175 million of unsecured debentures at 3.69% under the base shelf prospectus. The net proceeds from the issuance were used to repay short-term borrowings and to finance capital expenditures.

In November 2016 Fortis filed a short-form base shelf prospectus, under which the Corporation may issue common or preference shares, subscription receipts or debt securities in an aggregate principal amount of up to $5 billion during the 25-month life of the base shelf prospectus. In July 2017 Fortis exchanged its US$2.0 billion ($2.6 billion) unregistered senior unsecured notes for US$2.0 billion ($2.6 billion) registered senior unsecured notes under the base shelf prospectus. In March 2017 Fortis issued $500 million common equity and in December 2016 issued $500 million unsecured notes at 2.85%, both under the base shelf prospectus. A principal amount of approximately $1.5 billion remains under the base shelf prospectus.

As at December 31, 2017, management expects consolidated fixed-term debt maturities and repayments to be $394 million in 2018 and to average approximately $650 million annually over the next five years. The combination of available credit facilities, the US$400 million commercial paper program at ITC, and manageable 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" section of this MD&A.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2017 and are expected to remain compliant in 2018.

On February 14, 2018, the Corporation's Board of Directors authorized an at-the-market common equity offering ("ATM Program") of up to $500 million. The ATM Program will be established under a prospectus supplement to the Corporation's Canadian base shelf prospectus and U.S. shelf registration statement, and is subject to obtaining exemptive relief from Canadian securities regulators and other regulatory approvals, and the entering into arrangements with agents. The establishment of an ATM Program does not obligate the Corporation to issue any common equity.

CREDIT FACILITIES

As at December 31, 2017, the Corporation and its subsidiaries had consolidated credit facilities of approximately $5.0 billion, of which approximately $3.9 billion was unused, including $1.1 billion unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with large banks in Canada and the United States, with no one bank holding more than 20% of these facilities. Approximately $4.7 billion of the total credit facilities are committed facilities with maturities ranging from 2019 through 2022.

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

Credit Facilities As at December 31 *($ millions)*	Regulated Utilities	Corporate and Other	**2017**	2016
Total credit facilities [(1)]	3,567	1,385	**4,952**	5,976
Credit facilities utilized:				
Short-term borrowings [(1)]	(209)	—	**(209)**	(1,155)
Long-term debt (including current portion) [(2)]	(465)	(206)	**(671)**	(973)
Letters of credit outstanding	(73)	(56)	**(129)**	(119)
Credit facilities unused	2,820	1,123	**3,943**	3,729

(1) As at December 31, 2017, there was no commercial paper outstanding (December 31, 2016 - $195 million). Outstanding commercial paper does not reduce available capacity under the Corporation's consolidated credit facilities.

(2) As at December 31, 2017, credit facility borrowings classified as long-term debt included $312 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2016 - $61 million).

As at December 31, 2017 and 2016, 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
ITC has a total of US$900 million in unsecured committed revolving credit facilities maturing in October 2022. ITC has an ongoing commercial paper program in an aggregate amount of US$400 million, under which ITC had no amounts outstanding as at December 31, 2017.

UNS Energy has a total of US$500 million in unsecured committed revolving credit facilities, maturing in October 2022.

Central Hudson has a combined US$250 million unsecured committed revolving credit facility, with US$50 million maturing in July 2020 and the remaining maturing in October 2020. Central Hudson also has an uncommitted credit facility totalling US$40 million.

FortisBC Energy has a $700 million unsecured committed revolving credit facility, maturing in August 2022.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2022.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2022, and a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2022, 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 $40 million unsecured committed revolving credit facility, maturing in June 2020.

Caribbean Utilities has unsecured credit facilities totalling US$50 million. Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$22 million, and an emergency standby loan of US$25 million both maturing in June 2018.

Corporate and Other
Fortis has a $1.3 billion unsecured committed revolving credit facility, maturing in July 2022. The Corporation has the option to increase the facility by an amount up to $0.5 billion and, as at December 31, 2017, that option had not been exercised. In March 2017 the Corporation repaid a $500 million non-revolving term senior unsecured equity bridge credit facility, used to finance a portion of the cash purchase price of the acquisition of ITC, with proceeds from the issuance of common shares. Fortis issued approximately 12.2 million common shares, in a private placement to an institutional investor, representing share consideration of $500 million at a price of $41.00 per share.

FHI has a $50 million unsecured committed revolving credit facility, maturing in April 2020.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $129 million as at December 31, 2017 (December 31, 2016 - $119 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 principal risks that could materially affect its business, results of operations, financial condition or cash flows. Other risks may arise or risks not currently considered material may become material in the future.

The Corporation's utilities are subject to substantial regulation and its results of operation, financial condition and cash flows may be affected by regulatory or legislative changes.

Regulated utility assets represented approximately 97% of total assets of Fortis as at December 31, 2017 (December 31, 2016 – 97%). Approximately 97% of the Corporation's operating revenue[1] was derived from regulated operations in 2017 (2016 – 97%), and approximately 92% of the Corporation's operating earnings[1] were derived from regulated operations in 2017 (2016 – 93%). The Corporation operates utilities in different jurisdictions, including five Canadian provinces, nine U.S. States and three Caribbean countries.

The Corporation's utilities are subject to regulation by various federal, state and provincial regulators that can affect future revenue and earnings. These regulators administer various acts and regulations covering material aspects of the utilities' business, including, among others: electricity and gas tariff rates charged to customers; the allowed ROEs and deemed capital structures of the utilities; electricity and gas infrastructure investments; capacity and ancillary services; the transmission and distribution of energy; the terms and conditions of procurement of electricity for customers; issuances of securities; the provision of services by affiliates and the allocation of those service costs; certain accounting matters; and certain aspects of the siting and construction of transmission and distribution systems. Any decisions made by such regulators could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities. In addition, there is no assurance that the utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having a corresponding approved revenue requirement.

The Corporation's utilities follow COS regulation in determining annual revenue requirements and resulting customer rates, under which the ability of the utility to recover the actual cost of service and earn the approved ROE and/or ROA may depend on achieving the forecasts established in the rate-setting process. Failure of a utility to meet such forecasts could adversely affect the Corporation's results of operations, financial condition and cash flows. When PBR mechanisms are utilized, 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, in the event that inflationary increases exceed the inflationary factor set by the regulator or the utility is unable to achieve productivity improvements, the Corporation's results of operations, financial condition and cash flows may be adversely impacted. In the case of FortisAlberta's current PBR mechanism, there is a risk that capital expenditures may not qualify, or be approved, for incremental funding where necessary.

The Corporation and its utilities must address the effects of regulation, including compliance costs imposed on operations as a result of such regulation. The political and economic environment has had, and may continue to have, an adverse effect on regulatory decisions with negative consequences for the Corporation's utilities, including the cancellation or delay of planned development activities or other capital expenditures, and the incurrence of costs that may not be recoverable through rates. In addition, the Corporation is unable to predict future legislative or regulatory changes, and there can be no assurance that it will be able to respond adequately or in a timely manner to such changes. Such legislative or regulatory changes may increase costs and competitive pressures on the Corporation and its utilities. Any of these events could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

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[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 measures used by the chief operating decision maker in evaluating the performance of the Corporation's operating subsidiaries.

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

Certain elements of ITC's regulated operating subsidiaries' formula rates can be and have been challenged, which could result in lowered rates and/or refunds of amounts previously collected, and could have an adverse effect on ITC's business, results of operations, financial condition and cash flows.

ITC's regulated operating subsidiaries provide transmission service under rates regulated by FERC. FERC has approved the cost-based formula rates used to calculate the annual revenue requirement, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of ITC's rates approved by FERC, including the formula rate templates, the rates of return on the actual equity portion of capital structure and the approved targeted capital structure, are subject to challenge by interested parties, or by FERC. In addition, interested parties may challenge ITC's annual implementation and calculation of projected rates and formula rate true up pursuant to their approved formula rates under their formula rate implementation protocols. End-use customers and entities supplying electricity to end-use customers may also attempt to influence government and/or regulators to change the rate-setting methodologies that apply to ITC, particularly if rates for delivered electricity increase substantially. If it is established that rates are unjust and unreasonable or that the terms of service provision are unduly discriminatory or preferential, then FERC can make appropriate prospective adjustments. This could result in lowered rates and/or refunds of amounts collected, any of which could have an adverse effect on ITC's business, results of operations, financial condition and cash flows.

For additional information on current third-party complaints with FERC regarding the MISO regional base ROE for certain of ITC's regulated operating subsidiaries, refer to the "Regulatory Highlights" section of this MD&A.

Changes in interest rates could have an adverse effect on the Corporation's results of operations, financial condition and cash flows.

Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. The regulatory process may consider the general level of interest rates as a factor for setting allowed ROEs. A low interest rate environment could adversely affect the allowed ROEs at the Corporation's utilities, which could have a negative effect on the results of operations, financial condition and cash flows of the Corporation. Alternatively, if interest rates increase, regulatory lag may cause a delay in any resulting increase in the allowed ROEs to compensate for higher cost of capital.

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. At the utilities, interest expense is generally recovered in customer rates, as approved by the regulators. The inability to flow through interest costs to customers could have an adverse effect on the results of operations, financial condition and cash flows of the utilities. In addition, a change in the level of interest rates could affect the measurement and disclosure of the fair value of long-term debt.

If the generation, transmission and distribution facilities of the Corporation's utilities do not operate as expected, this could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and its utilities.

The ongoing operation of the utilities' facilities involves risks customary to the electric and gas utility industry, including 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 utilities. Such occurrences could result in service disruptions and the inability to deliver electricity or gas to customers in an efficient manner, resulting in 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 cost recovery.

The operation of the Corporation'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 Fortis will continue to operate in accordance with expectations.

The operation of electricity transmission and distribution assets is also subject to certain risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. Certain of the Corporation's utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature. 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 Corporation's gas utilities are exposed to various operational risks associated with gas, including fires, explosions, 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 gas that could result in significant operational disruptions and/or environmental liability.

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. For further detail on the Corporation's insurance coverage, refer to the insurance coverage risk discussion within the "Business Risk Management" section of this MD&A.

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 an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Generally, the Corporation's utilities have designed their electricity and 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 generate, transmit and distribute electricity and gas, which could have an adverse effect on the operations of the utilities, as well as harm the reputation of the Corporation and the respective utility.

Changes in energy laws, regulations or policies could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and its utilities.

The political, regulatory and economic environment may have an adverse effect on the regulatory process and limit the ability of the Corporation's utilities to increase earnings or achieve authorized rates of return. The disallowance of the recovery of costs incurred by the Corporation's utilities, or a decrease in the ROE/ROA, could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows. Fortis cannot predict whether the approved rate methodologies for any of its utilities will be changed. In addition, the U.S. Congress periodically considers enacting energy legislation that could assign new responsibilities to FERC, modify provisions of the U.S. Federal Power Act, or the Natural Gas Act, as amended, or provide FERC or another entity with increased authority to regulate U.S. federal energy matters. The Corporation cannot predict whether, and to what extent, its utilities may be affected by changes in energy laws, regulations or policies in the future.

Failure by the Corporation's applicable utilities to comply with required reliability standards could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and its utilities.

As a result of the Energy Policy Act of 2005, owners, operators and users of the bulk electric system in the United States are subject to mandatory reliability standards developed by the North American Electric Reliability Corporation and its regional entities, which are approved and enforced by FERC. Many of these reliability standards have also been adopted, sometimes with modifications, in certain Canadian provinces, including British Columbia, Alberta and Ontario. The standards prescribe benchmarks and measures that are designed to ensure that the bulk electric system operates reliably. Increased reliability standard compliance obligations may cause higher operating costs and/or capital expenditures for the Corporation's utilities. If any of the Corporation's utilities were found to be in violation of mandatory reliability standards, it could also be subject to significant penalties. Both the costs of regulatory compliance and the costs that may be imposed due to actual or alleged compliance failures could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

Energy sales of the Corporation's utilities may be negatively impacted by changes in general economic, credit and market conditions.

The Corporation's utilities are affected by energy demand in the jurisdictions in which they operate, which may change as a result of fluctuations in general economic conditions, energy prices, employment levels, personal disposable income, and housing starts. Significantly reduced energy demand in the Corporation's service territories could 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 may have an adverse effect on the Corporation's results of operations, financial condition and cash flows despite regulatory measures that may be available to compensate for reduced demand. In addition, an extended decline in economic conditions could make it more difficult for customers to pay for the electricity and gas they consume, thereby affecting the aging and collection of the utilities' trade receivables.

If the Corporation and/or its subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt, the financial condition of the Corporation and its subsidiaries could be adversely impacted.

The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial condition of the Corporation and its subsidiaries, the regulatory environment in which the Corporation's utilities operate and the 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 or 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 2018 are expected to total $394 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 to replace maturing indebtedness. Activity in the global capital markets may impact the cost and timing of issuance of long-term debt by the Corporation and its subsidiaries. Although the Corporation and its subsidiaries have been successful at raising long-term capital at reasonable rates, the cost of raising capital could increase and there can be no assurance that the Corporation and its subsidiaries will continue to have reasonable access to capital in the future.

Generally, the Corporation and its utilities rated by credit rating agencies 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 credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities.

In 2017 the following changes occurred to the debt credit ratings of the Corporations' utilities. In April 2017 S&P upgraded TEP's unsecured debt rating to 'A-' from 'BBB+' and in September 2017 S&P upgraded ITC's unsecured debt rating to 'A-' from 'BBB+'. 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.

The Corporation is subject to risks associated with its growth strategy that may adversely affect its business, results of operations, financial condition and cash flows, and actual capital expenditures may be lower than planned.

The Corporation has a history of growth through acquisitions and organic growth from capital expenditures in existing service territories. Acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and the Corporation may incur material unexpected costs. The Corporation's capital expenditure plan generally consists of a large number of individually small projects; however, the Corporation and its utilities are also involved in a number of major capital projects. Risks related to such major capital projects include delays and project cost overruns. Capital expenditures at the utilities are generally approved by the respective regulator; however, there is no assurance that any project cost overruns would be approved for recovery in customer rates. The failure to realize expected benefits of an acquisition and/or cost overruns on major capital projects could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

Additionally, the Corporation's five-year capital expenditure program and associated rate base growth are key assumptions in the Corporation's targeted dividend growth guidance. Actual capital expenditures may be lower than planned due to factors beyond the Corporation's control, which would result in a lower-than-anticipated rate base and have an adverse effect on the Corporation's results of operations, financial condition and cash flows. This could limit the Corporation's ability to meet its targeted dividend growth.

Cyber-security breaches, acts of war or terrorism, grid disturbances or security breaches involving the misappropriation of sensitive, confidential and proprietary customer, employee, financial or system operating information could significantly disrupt the business operations of the Corporation and its subsidiaries and have an adverse effect on its reputation.

As operators of critical energy infrastructure, the Corporation's utilities face a heightened risk of cyber-attacks. Information and operations 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, customer and employee 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, transmission and distribution facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

In the event the Corporation's utilities' information or operations technology systems are breached, service disruptions, property damage, corruption or unavailability of critical data or confidential employee or customer information could result. A material breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators, financial markets and expose it to claims for third-party damage. The financial impact of a material breach in cyber-security, act of war or terrorism could be material and may not be covered by insurance policies or, in the case of utilities, through regulatory cost recovery.

The Corporation's utilities may be subject to seasonality and their respective operations and electricity generation may fall below expectations due to the impact of severe weather or other natural events, which could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and its utilities.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and could impact the operations, results of operations, financial condition and cash flows of the electric utilities. In central and western Canada, Arizona and New York State, cool summers may reduce the use of air conditioning and other cooling equipment, while less severe winters may reduce electric heating load.

At the Corporation's gas utilities, 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 the Corporation's gas utilities are highest in the first and fourth quarters.

Regulatory deferral mechanisms are in place at certain of the Corporation's utilities to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence of these regulatory deferral mechanisms could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation and its utilities.

Despite preparations for severe weather, ice, wind and snow storms, hurricanes and other natural disasters, weather will always remain a risk to the physical assets of utilities. Climate change 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 can be no assurance that they will successfully do so in all circumstances.

Earnings from non-regulated generation assets in Belize and British Columbia are sensitive to rainfall levels and the related impact on water flows. Hydrologic risk associated with hydroelectric generation at the Waneta Expansion and FortisBC Electric is reduced by the Canal Plant Agreement, under which fixed energy and capacity entitlements will be received based upon long-term average water flows. 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 entitlement of the Waneta Expansion and FortisBC Electric to capacity and energy under the Canal Plant Agreement.

The Corporation's risk management policies cannot fully eliminate the risk associated with commodity price movements, which may have an adverse effect on the results of operations, financial condition and cash flows of the Corporation and its utilities.

The Corporation's utilities have exposure to long-term and short-term commodity price volatility, including changes in the market price of gas, world oil prices, which affect the cost of fuel, coal and purchased power. The risk of price volatility is substantially mitigated by the utilities' ability to flow through to customers the cost of gas, 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 gas, fuel and purchased power alleviates the effect on earnings of commodity price volatility. This risk has also been reduced by entering into various price-risk management strategies to reduce exposure to changing commodity rates, including the use of derivative contracts that effectively fix the price of gas, fuel sources and electricity purchases. The inability to utilize such hedging mechanisms in the future could result in increased exposure to market price volatility.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of gas, fuel, coal and purchased power will continue to exist in the future. Also, a severe and prolonged increase in such costs could have an adverse effect the Corporation's utilities, despite regulatory measures available to compensate for changes in these costs. The inability of the regulated utilities to flow through the full cost of gas, fuel, coal and purchased power could have an adverse effect on the utilities' results of operations, financial condition and cash flows.

Increased foreign exchange exposure may have an adverse effect on the Corporation's earnings and the value of its assets.

A significant portion of the Corporation's assets, earnings and cash flows are denominated in US dollars. The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar. The earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. Although the Corporation has limited this exposure through the use of US dollar-denominated borrowings at the corporate level, such actions may not completely mitigate this exposure. 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. As at December 31, 2017, the Corporation's corporately issued US$3,385 million (December 31, 2016 – US$3,511 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, 2017, the Corporation had approximately US$7,548 million (December 31, 2016 – US$7,250 million) in foreign net investments that were unhedged.

Consolidated earnings and cash flows of Fortis are impacted by fluctuations in the US dollar-to-Canadian dollar exchange rate. On an annual basis, it is estimated that a 5 cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.25 as at December 31, 2017 would increase or decrease earnings per common share of Fortis by approximately 6 cents, which reflects a hedging program implemented in 2017.

The Corporation entered into foreign exchange contracts to manage a portion of its exposure to foreign currency risk. There is no guarantee that such hedging strategies will be effective. In addition, currency hedging entails a risk of liquidity and, to the extent that the US dollar depreciates against the Canadian dollar, such hedges could result in losses greater than if hedging had not been used. Hedging arrangements may have the effect of limiting or reducing the Corporation's total returns if management's expectations concerning future events or market conditions prove to be incorrect, in which case the costs associated with the hedging strategies may outweigh their benefits.

Changes in tax laws could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and its subsidiaries.

The Corporation and its subsidiaries are subject to changes in tax legislation and tax rates in Canada, the United States and other international jurisdictions. A change in tax legislation or tax rates could adversely affect the business, results of operations, financial condition and cash flows of the Corporation and its subsidiaries.

U.S. Tax Reform resulted in significant changes to tax legislation in the United States, requiring a one-time remeasurement of the deferred income tax assets and liabilities of the Corporation's U.S. subsidiaries as at December 22, 2017, the date of enactment, and an unfavourable earnings impact of $168 million recorded in deferred income tax expense. For further details on the 2017 impact of U.S. Tax Reform refer to the "Significant Item" section of this MD&A.

The Corporation does not expect its future earnings to be materially adversely affected by U.S. Tax Reform; however, near-term cash flows of the Corporation's U.S. subsidiaries will be adversely affected as a reduced corporate tax rate will result in the recovery and collection of lower taxes from customers. The Corporation is evaluating the impacts of U.S. Tax Reform on its credit metrics and is committed to maintaining its investment-grade credit ratings.

The Corporation has debt at its U.S. utilities and holding companies and U.S. Tax Reform provides limitations on the deductibility of interest. While interest deductibility for regulated utilities has been retained, some uncertainty exists as to whether interest on holding company debt of a regulated utility would also be fully deductible. A reduction in the amount of interest expense deductible for income tax purposes could have an adverse effect on the Corporation's results of operations, financial condition and cash flows.

The timing or impacts of any future changes in tax laws, including the impacts of any subsequent technical corrections to existing tax laws, cannot be predicted. Additionally, certain aspects of the U.S. Tax Reform are still subject to interpretation. Therefore, there may be further impacts on the results of operations, financial condition and cash flows of the Corporation and its U.S. utilities beyond those described herein.

The Corporation and certain of its subsidiaries are subject to counterparty default risks and credit risk associated with amounts owing from customers and counterparties to derivative instruments. Any non-payment or non-performance by customers of the Corporation's subsidiaries or the derivative counterparties could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and these applicable subsidiaries.

ITC derives approximately 69% of its revenue from the transmission of electricity to three primary customers. While such customers have investment-grade credit ratings, any failure by such customers to make payments for transmission services could have an adverse effect on ITC's business, results of operations, financial condition and cash flows.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. FortisAlberta reduces its credit risk exposure by obtaining from the retailers either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and the Corporation may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Netting arrangements are used to reduce credit risk and net settle payment with counterparties where net settlement provisions exist. Credit risk is limited by mostly dealing with counterparties that have investment-grade credit ratings. Non-performance by counterparties could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation and these applicable subsidiaries.

The competitiveness of gas relative to alternative energy sources could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

If the gas sector becomes less competitive due to pricing or other factors, this could have an adverse effect on the Corporation's utilities that are involved in gas distribution and sales. In British Columbia, gas primarily competes with electricity for space and hot water heating load. In addition to other price comparisons, upfront capital costs between electric and gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of gas on a full-cost basis.

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

Government policy has also impacted the competitiveness of 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 impact the competitiveness of gas relative to non-carbon-based or other energy sources.

There are other competitive challenges impacting the penetration of gas in new housing supply, such as the green attributes of the energy source and the type of housing being built. In addition, municipal and other government policy may regulate or restrict the energy source permitted in new and existing developments.

A disruption in the wholesale energy markets or failure by an energy or fuel supplier could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and its utilities.

A significant portion of the electricity and gas that the Corporation's utilities sell to full-service customers is purchased through the wholesale energy markets or pursuant to contracts with energy suppliers. A disruption in the wholesale energy markets or a failure on the part of energy or fuel suppliers, or operators of energy delivery systems that connect to the utilities, could adversely affect such utilities' ability to meet their customers' energy needs and could adversely affect the Corporation's business, results of operations, financial condition and cash flows.

Pension and post-retirement benefit plans could require significant future contributions to such plans.

Fortis and the majority of its subsidiaries maintain a combination of defined benefit pension and/or other post-employment benefit ("OPEB") plans for certain of their employees and retirees. The most significant cost drivers of these benefit plans are investment performance and interest rates, which are affected by global financial and capital markets. Financial market disruptions and significant declines in the market values of the investments held to meet the pension and post-retirement obligations, discount rate assumptions, participant demographics and increasing longevity, and changes in laws and regulations may require the Corporation and its utilities to make significant funding contributions to the plans. Large funding requirements or significant increases in expenses could adversely impact the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Certain generation assets of the Corporation's utilities are jointly owned with, or are operated by, third parties. Therefore, the utilities may not have the ability to affect the management or operations at such facilities, which could have an adverse effect on their respective businesses, and the results of operations, financial condition and cash flows of the Corporation and these utilities.

Certain of the generating facilities 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 generating facilities. Further, TEP may have no or limited ability to make determinations on how best to manage the changing economic conditions or environmental requirements that may affect such facilities. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business, results of operations, financial condition and cash flows.

Advances in technology could impair or eliminate the competitive advantage of the Corporation's utilities.

The emergence of initiatives designed to reduce greenhouse gas emissions and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce power, enable more efficient storage of energy or reduce power consumption. 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 the business, results of operations, financial condition and cash flows of the Corporation's utilities. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. The Corporation's utilities are promoting demand-side management programs designed to help customers reduce their energy usage. These technologies include energy derived from renewable energy sources, 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 have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Environmental risks, including effects of climate change, fires, floods, contamination of air, soil or water from hazardous substances, natural gas leaks and hazardous or toxic emissions from the combustion of fuel required in the generation of electricity could cause the Corporation and its utilities to incur significant financial losses.

The Corporation's electric and gas utilities are subject to environmental risks. Risks associated with fire damage vary depending on 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 if it is found that such facilities were responsible for a fire, and such claims, if successful, could be material. Environmental risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the utility at the time it was the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to: (i) the transportation, handling and storage of large volumes of fuel; (ii) the use of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities; (iii) hazardous or toxic emissions from the combustion of fuel required in the generation of electricity; and (iv) management and disposal of coal combustion residuals and other wastes. The risk of contamination of air, soil or water at the gas utilities primarily relates to gas and propane leaks and other accidents involving these substances.

Liabilities relating to investigation and remediation of contamination, as well as claims for personal injury or property damage, may arise at many locations, including formerly owned or operated properties and sites where wastes have been treated or disposed of, as well as properties the utilities currently own or operate. Such liabilities may arise even where the contamination does not result from non-compliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that a party can be held responsible for more than its share of the liability involved, or even the entire liability. Additional risks include accidents resulting in hazardous release at or from coal mines that supply generating facilities in which the Corporation's utilities have 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 any failure of containment of large volumes of water for the purpose of electricity generation. Such inherent environmental risks could subject the Corporation and its utilities to litigation and administrative proceedings that could result in substantial monetary judgments for clean-up costs, damages, fines or penalties. To the extent that the occurrence of any of these events is not fully covered by insurance, they could adversely affect the utilities' results of operations, financial condition and cash flows.

Furthermore, the Corporation's electric and gas utilities are subject to U.S. and Canadian federal, state and provincial environmental laws and regulations, including those which impose limitations or restrictions on the discharge of pollutants into the air and water, establish standards for the management, treatment, storage, transportation and disposal of solid and hazardous wastes and hazardous materials, and impose obligations to investigate and remediate contamination in certain circumstances. The Corporation's utilities have incurred expenses in connection with environmental compliance, and they anticipate that they will continue to do so in the future. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a negative effect on the Corporation's and its utilities' results of operations, financial condition and cash flows.

In particular, the management of greenhouse gas emissions is a concern for the Corporation's regulated utilities in Canada and the United States, primarily due to new and emerging federal, state and provincial greenhouse gas laws, regulations and guidelines. For example, in 2015, the federal government in the United States issued the Clean Power Plan, which would regulate greenhouse gas emissions from existing fossil fuel-fired generating units. In 2017 the Environmental Protection Agency signed a proposal to repeal the Clean Power Plan and has not determined whether or not a replacement rule will be issued. The utilities continue to develop compliance strategies and assess the impact that such legislative changes may have on future operations, as well as the costs to comply with these potential new requirements. However, due to the significant current uncertainties related to federal and state regulation of greenhouse gas emissions in the United States, the ultimate financial and operational impact of such regulation cannot be determined at this time.

Some of the coal-fired generating facilities, from which the utilities obtain power, will be closed before the end of their useful lives in response to economic conditions and/or recent or future changes in environmental regulation, including potential regulation relating to greenhouse gas emissions. If such early closures occur, the utilities may need to seek from its regulator the recovery of any remaining net book value and could incur additional expenses relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating facilities. Any unrecovered costs, if substantial, could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation's utilities.

The Corporation and its subsidiaries are not able to insure against all potential risks and may become subject to loss of coverage, higher insurance premiums and failure by insurers to satisfy eligible claims.

The Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their physical 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' transmission and distribution assets are 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 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, loss of revenue and customer claims that are substantial in amount and could have an adverse effect on the Corporation's business, results of operations, financial position and cash flows. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or material damage that is self-insured, could have an adverse effect on the Corporation's business, results of operations, financial position and cash flows.

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, 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.

Certain of the Corporation's regulated utilities and non-regulated energy infrastructure operations may not be able to obtain or maintain all required approvals.

The acquisition, ownership and operation of electric and gas utilities and assets require numerous licenses, permits, agreements, orders, approvals and certificates from various levels of government, government agencies and/or third parties. For various reasons, including increased stakeholder participation, the Corporation's regulated utilities and non-regulated energy infrastructure operations may not be able to obtain or maintain all required approvals. If there is a delay in obtaining any required approvals, failure to obtain or maintain any required approvals, failure 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 an adverse effect on the results of operations, financial condition and cash flows of the Corporation and its utilities.

The Corporation's failure to comply with Section 404(a) of the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley") on an ongoing basis, could adversely affect investor confidence and harm its reputation.

The Corporation's internal control over financial reporting are required to be in compliance with the requirements of Section 404(a) of Sarbanes-Oxley, and the related rules of the Securities Exchange Commission and the Public Company Accounting Oversight Board. The Corporation's failure to satisfy the requirements of Section 404(a) on an ongoing basis, or any failure in its internal controls, could result in the loss of investor confidence in the reliability of its financial statements, which could have an adverse effect on its results of operations, financial condition and cash flows, as well as harm its reputation. Further, there can be no assurance that the Corporation's independent auditors will be able to provide the required attestation.

Increased external stakeholder activism could have an adverse effect on the Corporation's ability to execute capital expenditure programs.

External stakeholders are increasingly challenging investor-owned utilities in the areas of climate change, sustainability, diversity, utility ROEs and executive compensation. In addition, public opposition to larger infrastructure projects is becoming increasingly common, which can challenge a utility's ability to execute capital expenditure programs. While the Corporation is actively monitoring activism and is committed to developing stronger relationships with its external stakeholders, failure to effectively respond to public opposition may adversely affect the Corporation's capital expenditure programs and, therefore, future organic growth, which could adversely affect its results of operations, financial condition and cash flows.

Certain of the Corporation's subsidiaries have facilities and provide limited services on lands that are subject to land claims by various First Nations, which may subject the utilities to various legal, administrative and land-use proceedings.

The Corporation's utilities in British Columbia provide service to customers on First Nations' lands and maintain gas facilities and electric generation, transmission and distribution 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 Corporation's service territories 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 structure settlements without prejudicing existing rights held by third parties. However, there can be no certainty that the settlement process will not have an adverse effect on the results of operations, financial condition and cash flows the Corporation's utilities in British Columbia.

The Corporation has distribution assets on First Nations' lands in Alberta 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 be unable to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have an adverse effect on FortisAlberta.

The Corporation's utilities face the risk of strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms.

Most of the Corporation's utilities employ members of labour unions or associations that have entered into collective bargaining agreements with the utilities. The Corporation considers the relationships of its utilities 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 an adverse effect on the results of operations, financial condition and cash flows of the Corporation's utilities.

The Corporation's utilities may suffer the loss of key personnel or the inability to hire and retain qualified employees.

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

ITC enters into various agreements and arrangements with third parties to provide services for construction, maintenance and operations of certain aspects of its business, which, if terminated, could result in a shortage of a readily available workforce to provide these services. If any of these agreements or arrangements are terminated for any reason, ITC may face difficulty finding a qualified replacement work force to provide such services, which could have an adverse effect on the ability of ITC to carry on its business and on its results of operations.

The Corporation and its subsidiaries are subject to litigation or administrative proceedings.

The Corporation and its subsidiaries have been and continue to be involved in legal proceedings, administrative proceedings, claims and other litigation that arise in the ordinary course of business. These actions may include environmental claims, employment-related claims, securities-based litigation and contractual disputes or claims for personal injury or property damage that occur in connection with services performed relating to the operation of the utilities, or actions by regulatory or tax authorities. Unfavourable outcomes or developments relating to these proceedings or future proceedings, such as judgments for monetary damages, injunctions or denial or revocation of permits or settlement of claims, could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and its subsidiaries.

CHANGES IN ACCOUNTING POLICIES

The new US GAAP accounting policies that are applicable to, and were adopted by, Fortis, in 2017, are described as follows.

Simplifying the Test for Goodwill Impairment
Effective January 1, 2017, the Corporation adopted Accounting Standards Update ("ASU") No.2017-04, *Simplifying the Test for Goodwill Impairment.* The amendments in this update simplify the subsequent measurement of goodwill by eliminating step two in the current two-step goodwill impairment test. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. The above-noted ASU was applied prospectively and did not impact the Corporation's consolidated financial statements.

Inventories
Effective January 1, 2017, the Corporation's utilities adopted ASU No. 2015-11, *Inventory*, which requires the measurement of inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The adoption of this update did not impact the Corporation's consolidated financial statements as the cost of inventory at the Corporation's utilities is recovered in customer rates.

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 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, along with additional ASUs issued in 2016 and 2017 to clarify implementation guidance, create Accounting Standards Codification ("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 clarifies the principles for recognizing revenue and enables users of financial statements to better understand and consistently analyze an entity's revenues across industries and transactions. The new guidance permits two methods of adoption: (i) the full retrospective method; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption supplemented by additional disclosures. This standard is effective for annual and interim periods beginning after December 15, 2017. Fortis adopted this ASU on January 1, 2018 using the modified retrospective approach and there have been no material adjustments identified to opening retained earnings.

Fortis has reviewed the final assessments and conclusions of its utilities on tariff-based sales to retail and wholesale customers, which represents more than 90% of the Corporation's consolidated revenue, and has concluded that the adoption of this standard will not affect revenue recognition for tariff-based sales and, therefore, will not have an impact on earnings. Fortis' subsidiaries have completed their final assessments and conclusions on less material revenue streams, and Fortis is reviewing these final assessments, particularly for consistency of implementation and accounting policy selection, and does not expect any adjustments.

The Corporation will add additional disclosures to address the requirement to provide more information regarding the nature, amount, timing and uncertainty of revenue and cash flows, which will result in revenues that fall outside the scope of the new standard, including alternative revenue programs, being presented separately. The Corporation will present revenue in three categories: (i) revenue from contracts with customers which will include retail and wholesale tariff revenue; (ii) alternative revenue programs; and (iii) other revenue. The Corporation's revenue is currently disaggregated by: (i) geography; and (ii) substantially autonomous utility operations. This level of disaggregation will not change upon implementation of the new guidance as it is: (i) used by the Corporation's chief operating decision maker for evaluating the financial performance of operating subsidiaries and to make resource allocation decisions; (ii) used by external stakeholders for evaluating the Corporation's financial performance; and (iii) consistent with other externally reported documents of the Corporation.

Fortis continues to monitor its adoption process under its existing internal control over financial reporting, including accounting processes and the gathering and evaluation of information used in assessing the required disclosures. As the Corporation finalizes its implementation in the first quarter of 2018, it will continue to assess any necessary changes to internal control over financial reporting.

Recognition and Measurement of Financial Assets and Financial Liabilities
ASU No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*, was issued in January 2016 and the amendments in this update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. Most notably, the amendments require the following: (i) equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings; and (ii) financial assets and financial liabilities to be presented separately in the notes to the consolidated financial statements, grouped by measurement category and form of financial instrument. This update is effective for annual and interim periods beginning after December 15, 2017. Fortis will adopt this standard in the first quarter of 2018, with an effective date of January 1, 2018; however, it is not expected that this standard will have a material impact on its consolidated financial statements.

Leases
ASU No. 2016-02 was issued in February 2016 and the amendments in this update create ASC Topic 842, *Leases*, and supersede lease requirements in ASC Topic 840, *Leases*. The main provision of ASC Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows. These amendments also require qualitative disclosures along with specific quantitative disclosures. This update is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using a modified retrospective approach with practical expedient options. Early adoption is permitted. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments
ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, was issued in June 2016 and the amendments in this update require entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to inform credit loss estimates. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a modified retrospective basis. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* was issued in March 2017 and the amendments in this update require that an employer disaggregate the current service cost component of net benefit cost and present it in the same statement of earnings line item(s) as other employee compensation costs arising from services rendered. The other components of net benefit cost are required to be presented separately from the service cost component and outside of operating income. Additionally, the amendments allow only the service cost component to be eligible for capitalization when applicable. The amendments in this update should be applied retrospectively for the presentation of the net periodic benefit costs and prospectively, on and after the effective date, for the capitalization in assets of only the service cost component of net periodic benefit costs. This update is effective for annual and interim periods beginning after December 15, 2017. Fortis adopted this standard on January 1, 2018 and concluded that this standard will not materially impact its consolidated financial statements.

Targeted Improvements to Accounting for Hedging Activities

ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities,* was issued in August 2017 and the amendments in this update better align risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and presentation of hedge results. This update is effective for annual and interim periods beginning after December 15, 2018. Early adoption is permitted. The amendments in this update should be reflected as of the beginning of the fiscal year of adoption. For cash flow and net investment hedges existing at the date of adoption, the amendments should be applied as a cumulative effect adjustment related to eliminating the separate measurement of ineffectiveness to accumulated other comprehensive income with a corresponding adjustment to the opening balance of retained earnings. Amended presentation and disclosure guidance is required only prospectively. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements.

FINANCIAL INSTRUMENTS

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

Financial Instruments	**2017**		2016	
Liability as at December 31	**Carrying**	**Estimated**	Carrying	Estimated
($ millions)	**Value**	**Fair Value**	Value	Fair Value
Long-term debt, including current portion	**21,535**	**23,481**	21,219	22,523
Waneta Partnership promissory note	**63**	**64**	59	61

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 tables present, 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.

Financial Instruments Carried at Fair Value *($ millions)*	**December 31, 2017** **Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Energy contracts subject to regulatory deferral [(1)] [(2)]	**—**	**19**	**2**	**21**
Energy contracts not subject to regulatory deferral [(1)]	**—**	**26**	**4**	**30**
Foreign exchange contracts [(3)]	**3**	**—**	**—**	**3**
Other investments [(4)]	**78**	**—**	**—**	**78**
Total assets	**81**	**45**	**6**	**132**
Liabilities				
Energy contracts subject to regulatory deferral [(2)] [(5)]	**(1)**	**(103)**	**(2)**	**(106)**
Energy contracts not subject to regulatory deferral [(5)]	**—**	**—**	**(1)**	**(1)**
Interest rate and total return swaps [(3)]	**—**	**(1)**	**—**	**(1)**
Total liabilities	**(1)**	**(104)**	**(3)**	**(108)**

Financial Instruments Carried at Fair Value *($ millions)*	December 31, 2016 Level 1	Level 2	Level 3	Total
Assets				
Energy contracts subject to regulatory deferral [(1)] [(2)]	1	13	5	19
Energy contracts not subject to regulatory deferral [(1)]	—	1	2	3
Interest rate swaps [(3)]	—	11	—	11
Other investments [(4)]	69	—	—	69
Total assets	70	25	7	102
Liabilities				
Energy contracts subject to regulatory deferral [(2)] [(5)]	—	(21)	(5)	(26)
Energy contracts not subject to regulatory deferral [(5)]	—	(9)	—	(9)
Interest rate and total return swaps [(3)]	—	(3)	—	(3)
Total liabilities	—	(33)	(5)	(38)

(1) The fair value of the Corporation's energy contracts is recognized in accounts receivable and other current assets and long-term other assets.

(2) 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 future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

(3) The fair value of the Corporation's foreign exchange contracts, interest rate and total return swaps is recognized in accounts receivable and other current assets, accounts payable and other current liabilities and long-term other liabilities.

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

(5) The fair value of the Corporation's energy contracts is recognized in accounts payable and other current liabilities and non-current other liabilities.

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.

Energy Contracts Subject to Regulatory Deferral
UNS Energy holds electricity power purchase contracts and gas swap 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, transmission costs and line losses.

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

FortisBC Energy holds gas supply contracts and fixed-price financial swaps 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 published market prices and forward curves for natural gas.

These energy contracts 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 recognized in earnings. As at December 31, 2017, unrealized losses of $87 million (December 31, 2016 - $19 million) were recognized in regulatory assets and unrealized gains of $2 million were recognized in regulatory liabilities (December 31, 2016 - $12 million).

Energy Contracts Not Subject to Regulatory Deferral
UNS Energy holds wholesale trading contracts that qualify as derivative instruments to fix power prices and realize potential margin, of which 10% of any realized gains are shared with customers through UNS Energy's rate stabilization accounts. The fair value of the wholesale contracts was measured using a market approach using independent third-party information, where possible.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, to capture natural gas price spreads, and to manage the financial risk posed by physical transactions. The fair value of the gas swap contracts was calculated using forward pricing from published market sources.

These energy contracts were not designated as hedges and any unrealized gains or losses associated with changes in the fair value of the derivatives are recognized in revenue. As at December 31, 2017, unrealized gain of $36 million (December 31, 2016 - unrealized loss of $2 million) was recognized in earnings.

Foreign exchange contracts
The Corporation holds US dollar foreign exchange contracts to mitigate its exposure to volatility of foreign exchange rates. The foreign exchange contracts expire in 2018 and have a combined notional amount of $160 million. The fair value of the foreign exchange contracts was measured using a valuation approach using independent third-party information.

Any unrealized gains and losses are recognized in earnings. During 2017 unrealized gains of $3 million were recognized in earnings.

Interest rate and total return swaps
UNS Energy holds an interest rate swap to mitigate its exposure to volatility in variable interest rates on capital lease obligations. The interest rate swap agreement expires in 2020 and has a notional amount of $23 million.

The Corporation holds three total return swaps to manage the cash flow risk associated with forecasted future cash settlements of the respective DSU and RSU obligations. The total return swaps have a combined notional amount of $33 million and terms ranging from one to three years terminating in January 2018, 2019 and 2020.

In November 2017 ITC terminated its forward-starting interest rate swaps that were used to manage the interest rate risk associated with the November 2017 issuance of US$1 billion fixed-rate debt. As at December 31, 2017, ITC did not have any interest rate swaps outstanding.

The fair value of interest rate swaps at UNS Energy was determined based on an income valuation approach based on the six month LIBOR rates. The fair value of the Corporation's total return swaps was measured using the income valuation approach based on forward pricing curves.

The unrealized gains and losses on interest rate swaps, which qualify as cash flow hedges, are recognized in other comprehensive income and reclassified to earnings as a component of interest expense over the life of the hedged debt. The loss expected to be reclassified to earnings within the next twelve months is estimated to be approximately $3 million, net of tax. The unrealized gains and losses on the total return swaps are recognized in 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.

Other investments
ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for selected employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. The gains and losses on these funds are recognized in earnings and gains and losses on investments classified as available-for-sale are recognized in accumulated other comprehensive income.

Volume of Derivative Activity

As at December 31, 2017, the Corporation had various energy contracts that will settle on various expiration dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

Volume	**2017**	2016
Energy contracts subject to regulatory deferral (1)		
Electricity swap contracts (GWh)	**1,291**	2,184
Electricity power purchase contracts (GWh)	**761**	1,252
Gas swap contracts (PJ)	**216**	35
Gas supply contract premiums (PJ)	**219**	240
Energy contracts not subject to regulatory deferral (1)		
Wholesale trading contracts (GWh)	**2,387**	2,058
Gas supply contract premiums (PJ)	**—**	15
Gas swap contracts (PJ)	**36**	4

(1) GWh means gigawatt hours and PJ means petajoules.

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, they 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 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, 2017, Fortis recognized a total of $3.0 billion in regulatory assets (December 31, 2016 - $2.9 billion) and $3.4 billion in regulatory liabilities (December 31, 2016 - $2.2 billion). The increase in regulatory liabilities was primarily due to the impact of U.S. Tax Reform, reflecting the reduction in deferred income tax expense expected to be refunded to customers. For further discussion of the nature of regulatory decisions, refer to the "Regulatory Highlights" 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, 2017, the Corporation's consolidated property, plant and equipment and intangible assets were approximately $30.7 billion, or approximately 64% of total consolidated assets (December 31, 2016 - $30.3 billion, or approximately 63% of total consolidated assets). Depreciation and amortization was $1,179 million for 2017 (2016 - $983 million).

Depreciation rates of the Corporation's regulated utilities include an estimate for future asset removal costs that have not been identified as a legal obligation, with the amount provided for in depreciation expense recorded as a long-term regulatory liability. Actual asset removal costs are recorded against the regulatory liability when incurred. The estimate of asset removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2017 was $1.1 billion (December 31, 2016 - $1.2 billion).

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 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.

Capitalized Overhead: Most of the Corporation's utilities capitalize overhead costs that are not directly attributable to specific property, plant and equipment but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to property, plant and equipment is established by the utilities' respective regulator. Any change in the methodology of calculating and allocating general overhead costs to property, plant and equipment could have a material impact on the amount recognized as operating expenses versus property, plant and equipment.

Assessment for Impairment of Goodwill: Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets acquired relating to business acquisitions. The Corporation performs an annual impairment test for goodwill as at October 1, or more frequently if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value.

As at December 31, 2017, consolidated goodwill totalled approximately $11.6 billion (December 31, 2016 - $12.4 billion). The decrease in goodwill was due to the impact of foreign exchange associated with the translation of US dollar-denominated goodwill.

Fortis performs an annual internal qualitative and quantitative assessment for each reporting unit to which goodwill has been allocated. The Corporation has a total of 11 reporting units that were allocated goodwill at the respective dates of acquisition by Fortis and as at October 1, 2017, the Corporation completed its assessment of goodwill for all reporting units. The goodwill impairment test considered the impact of U.S. Tax Reform and confirmed that there is no impairment to goodwill.

For those reporting units where: (i) management's assessment of qualitative and quantitative 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 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.

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 method. The income approach uses several underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and the determination of appropriate discount rates. A secondary valuation method, the market approach, as well as a reconciliation of the total estimated fair value of all reporting units to the Corporation's market capitalization, is also performed as an assessment of the conclusions reached under the income approach.

As a result of the Corporation's annual assessment for impairment of goodwill, the fair value of all of the reporting units that were allocated goodwill exceeded their respective carrying value and, therefore, no impairment provision was required in 2017 or 2016.

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.

Employee Future Benefits:

Defined Benefit Pension Plans

The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments used in the actuarial determination of the net benefit cost and related obligation. The main assumptions used 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 2018, is 5.78%, which is down from 5.97% used for 2017. The decrease in the average long-term rate of return reflects lower expected returns from fixed income and equity investments. The defined benefit pension plan assets experienced total positive returns of approximately $336 million in 2017 compared to expected positive returns of $151 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 re-balancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2017, and to determine net pension cost for 2018, is 3.58%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2016, and to determine net pension cost for 2017, 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.

Consolidated defined benefit pension costs were comparable with 2016. Higher expected return on plan assets, lower amortization of actuarial losses and lower regulatory adjustments for 2017 compared to 2016, were largely offset by higher service and interest costs related to the acquisition of ITC. Any increases or decreases in defined benefit net pension cost at the regulated utilities for 2018 are expected to be recovered from or refunded to 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 2017 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2017 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate Year Ended December 31, 2017 **(Decrease) increase** *($ millions)*	**Net pension benefit cost**	**Projected benefit obligation** [1]
Impact of increasing the rate of return assumption by 100 basis points	(25)	21
Impact of decreasing the rate of return assumption by 100 basis points	21	(59)
Impact of increasing the discount rate assumption by 100 basis points	(33)	(422)
Impact of decreasing the discount rate assumption by 100 basis points	50	538

[1] At FortisBC Energy and FortisBC Electric certain defined benefit pension plans have pension indexing provisions that 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.

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.

At FortisAlberta, as approved by the regulator, the cost of defined benefit pension plans is recovered in customer rates based on the cash payments made with any difference between the cash payments made and the cost incurred being deferred as a regulatory asset or regulatory liability. ITC, 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. 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, 2017, for defined benefit pension plans, the Corporation had consolidated projected benefit obligations of $3.2 billion (December 31, 2016 - $3.0 billion) and consolidated plan assets of $2.8 billion (December 31, 2016 - $2.6 billion), for a consolidated funded status in a liability position of $0.4 billion (December 31, 2016 - $0.4 billion). In 2017 the Corporation recognized consolidated net pension benefit cost of $87 million (2016 - $88 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, along with the health care cost trend rate, were also used by management in determining net benefit OPEB cost and accumulated benefit obligation.

The OPEB plan assets at ITC, UNS Energy and Central Hudson experienced positive returns of $37 million in 2017 compared to expected positive returns of approximately $14 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 2017 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2017 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate
Year Ended December 31, 2017

Increase (decrease) *($ millions)*	**Net OPEB cost**	**Accumulated benefit obligation**
Impact of increasing the health care cost trend rate assumption by 100 basis points	16	96
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(11)	(74)
Impact of increasing the discount rate assumption by 100 basis points	(8)	(92)
Impact of decreasing the discount rate assumption by 100 basis points	11	116

ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in actual cost from forecast to be recovered from, or refunded to, customers in future rates. 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, 2017, for OPEB plans, the Corporation had consolidated accumulated benefit obligations of $665 million (December 31, 2016 - $676 million) and consolidated plan assets of $277 million (December 31, 2016 - $252 million), for a consolidated funded status in a liability position of $388 million (December 31, 2016 - $424 million). In 2017 the Corporation recognized consolidated net OPEB benefit cost of $32 million (2016 - $30 million).

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.

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 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 to revenue in the periods they become known, when actual results differ from estimates. As at December 31, 2017, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $575 million (December 31, 2016 - $551 million) on consolidated revenue of $8.3 billion for 2017 (2016 - $6.8 billion).

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, results of operations or cash flows.

The following describes the nature of the Corporation's contingency.

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. In May 2016 the Federal Court entered a decision dismissing the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the minister's consent and returned the matter to the minister for redetermination. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Comparative Figures in the Consolidated Statement of Cash Flows

During the year ended December 31, 2017, the Corporation discovered an immaterial error with respect to the presentation of credit facility borrowings within the financing section of its Statement of Cash Flows. The Corporation evaluated the error and determined that there was no impact to its results of operations or financial position in previously issued financial statements and that the impact was not material to its cash flows in previously issued financial statements. For the year ended December 31, 2016, the correction resulted in $169 million, which was previously reported within Net Repayments and Borrowings under Committed Credit Facilities, being reported on a gross basis, with $668 million reported as Borrowings under Committed Credit Facilities and $499 million being reported as Repayments under Committed Credit Facilities. The correction did not change the total cash from financing activities.

The immaterial error also occurred in the Consolidated Statement of Cash Flows for the periods ended March 31, 2016, June 30, 2016, September 30, 2016, December 31, 2016, March 31, 2017, June 30, 2017 and September 30, 2017. The following table details the correction of the error.

	Quarter Ended				Annual
($ millions)	March 2016	June 2016	September 2016	December 2016	2016
As reported					
Net repayments and borrowings under committed credit facilities	92	421	83	(503)	93
As corrected					
Borrowings under committed credit facilities	105	124	72	367	668
Repayments under committed credit facilities	(82)	(58)	(99)	(260)	(499)
Net borrowings and repayments under committed credit facilities	69	355	110	(610)	(76)

	Quarter Ended			Year to Date
($ millions)	March 2017	June 2017	September 2017	September 2017
As reported				
Net repayments and borrowings under committed credit facilities	65	(241)	(221)	(397)
As corrected				
Borrowings under committed credit facilities	483	324	659	1,466
Repayments under committed credit facilities	(545)	(507)	(648)	(1,700)
Net borrowings and repayments under committed credit facilities	127	(58)	(232)	(163)

RELATED-PARTY AND INTER-COMPANY 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. There were no material related-party transactions in 2017 or 2016.

Inter-company balances and inter-company transactions, including any related inter-company profit, are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The significant inter-company transactions for 2017 and 2016 are summarized in the following table.

Related-party and inter-company transactions Years ended December 31 *($ millions)*	**2017**	2016
Sale of capacity from Waneta Expansion to FortisBC Electric	**46**	45
Sale of energy from BECOL to Belize Electricity	**35**	33
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**24**	17

As at December 31, 2017, accounts receivable on the Corporation's consolidated balance sheet included approximately $20 million due from Belize Electricity (December 31, 2016 - $16 million).

From time to time, the Corporation provides short-term financing to certain subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements. There were no inter-segment loans outstanding as at December 31, 2017 and December 31, 2016.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2017, 2016 and 2015.

Selected Annual Financial Information Years ended December 31 *($ millions, except per share amounts)*	**2017**	2016	2015
Revenue	**8,301**	6,838	6,757
Net earnings	**1,125**	713	840
Net earnings attributable to common equity shareholders	**963**	585	728
Basic earnings per common share	**2.32**	1.89	2.61
Diluted earnings per common share	**2.31**	1.89	2.59
Total assets	**47,822**	47,904	28,804
Long-term debt (excluding current portion)	**20,691**	20,817	10,784
Preference shares	**1,623**	1,623	1,820
Common shareholders' equity	**13,380**	12,974	8,060
Dividends declared per:			
Common share	**1.65**	1.55	1.43
First Preference Share, Series E (1)	—	0.6126	1.2250
First Preference Share, Series F	**1.2250**	1.2250	1.2250
First Preference Share, Series G	**0.9708**	0.9708	0.9708
First Preference Share, Series H (2)	**0.6250**	0.6250	0.7344
First Preference Share, Series I (2)	**0.5262**	0.4874	0.3637
First Preference Share, Series J	**1.1875**	1.1875	1.1875
First Preference Share, Series K	**1.0000**	1.0000	1.0000
First Preference Share, Series M	**1.0250**	1.0250	1.0250

(1) In September 2016 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series E.

(2) 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 is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

2017/2016: Revenue increased $1,463 million, or 21.4%, from 2016 and net earnings attributable to common equity shareholders were $963 million, or $2.32 per common share, compared to $585 million, or $1.89 per common share, in 2016. For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders, and basic earnings per common share, refer to the "Summary Financial Highlights" and "Consolidated Results of Operations" sections of this MD&A.

Total assets and long-term debt were comparable to 2016. The impact of unfavourable foreign exchange on the translation of US dollar-denominated assets was largely offset by continued investment in energy infrastructure, driven by capital spending at the regulated utilities.

2016/2015: Revenue increased $81 million, or 1.2%, from 2015. The increase in revenue was driven by the acquisition of ITC in October 2016, contribution from Aitken Creek, and favourable foreign exchange associated with the translation of US dollar-denominated revenue. The increase was partially offset by lower non-utility revenue due to the sale of commercial real estate and hotel assets in 2015 and the flow through in customer rates of lower overall energy supply costs.

Net earnings attributable to common equity shareholders were $585 million in 2016 compared to $728 million in 2015. The decrease was primarily due to: (i) ITC acquisition-related expenses totalling $90 million, after tax, in 2016; (ii) gains on the sale of non-core assets totalling $133 million, after tax, in 2015; and (iii) lower earnings at FortisAlberta mainly due to lower average energy consumption and higher operating expenses. The decrease in net earnings attributable to common equity shareholders was partially offset by: (i) earnings contribution of $81 million at ITC from the date of acquisition in October 2016; (ii) strong performance at most of the Corporation's regulated utilities driven by UNS Energy, largely due to the settlement of Springerville Unit 1 matters, Central Hudson, due to an increase in delivery revenue, a higher AFUDC at FortisBC Energy, and stronger performance from the Caribbean; (iii) favourable foreign exchange associated with US dollar-denominated earnings; and (iv) contribution from Aitken Creek and higher earnings at the Waneta Expansion, which commenced production in early April 2015.

The growth in total assets was driven by the acquisition of ITC in October 2016 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities and the acquisition of Aitken Creek, partially offset by unfavourable foreign exchange on the translation of US dollar-denominated assets. The increase in long-term debt was primarily due to the financing of the acquisition of ITC, including debt assumed on acquisition, and the financing of energy infrastructure investments.

Basic earnings per common share were $1.89 in 2016 compared to $2.61 in 2015. The decrease was driven by lower earnings, as discussed above, and an increase in the weighted average number of common shares outstanding.

FOURTH QUARTER RESULTS

The following tables set forth financial information for the fourth quarters ended December 31, 2017 and 2016.

Summary of Electricity and Energy Sales and Gas Volumes			
Fourth Quarters Ended December 31	**2017**	2016	Variance
Regulated Utilities - United States			
UNS Energy - Electricity Sales *(GWh)*	**3,553**	3,356	197
UNS Energy - Gas Volumes *(PJ)*	**4**	4	—
Central Hudson - Electricity Sales *(GWh)*	**1,195**	1,195	—
Central Hudson - Gas Volumes *(PJ)*	**6**	6	—
Regulated Utilities - Canada			
FortisBC Energy *(PJ)*	**69**	67	2
FortisAlberta *(GWh)*	**4,328**	4,352	(24)
FortisBC Electric *(GWh)*	**869**	856	13
Eastern Canadian *(GWh)*	**2,177**	2,207	(30)
Regulated Utilities - Caribbean *(GWh)*	**199**	205	(6)
Non-Regulated - Energy Infrastructure *(GWh)*	**137**	115	22

Electricity and Energy Sales

The increase in electricity sales was driven by higher electricity sales at UNS Energy primarily due to higher long-term wholesale sales due to the commencement of a new contract in 2017. The increase was partially offset by lower energy deliveries at FortisAlberta, due to lower average consumption by residential and oil and gas customers, and a decrease in electricity sales at Eastern Canadian, due to an overall decrease in consumption.

Gas Volumes

Gas volumes were comparable with 2016.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders						
Fourth Quarters Ended December 31	Revenue			Net Earnings		
($ millions, except per share amounts)	**2017**	2016	Variance	**2017**	2016	Variance
Regulated Utilities - United States						
ITC	**396**	334	62	**(1)**	59	(60)
UNS Energy	**471**	468	3	**28**	29	(1)
Central Hudson	**211**	207	4	**22**	20	2
Regulated Utilities- Canada						
FortisBC Energy	**366**	393	(27)	**66**	70	(4)
FortisAlberta	**152**	143	9	**29**	30	(1)
FortisBC Electric	**107**	102	5	**13**	13	—
Eastern Canadian	**273**	278	(5)	**16**	16	—
Regulated Utilities - Caribbean	**74**	76	(2)	**9**	12	(3)
Non-Regulated						
Energy Infrastructure	**64**	54	10	**25**	15	10
Corporate and Other	**—**	2	(2)	**(73)**	(75)	2
Inter-Segment Eliminations	**(3)**	(4)	1	**—**	—	—
Total	**2,111**	2,053	58	**134**	189	(55)
Basic Earnings per Common Share *($)*				**0.32**	0.49	(0.17)
Weighted Average Number of Common Shares Outstanding *(# millions)*				**420.1**	384.6	35.5

Revenue
The increase in revenue was primarily due to the acquisition of ITC in October 2016, contribution from Aitken Creek, which is included in Energy Infrastructure, and higher capital tracker revenue at FortisAlberta. The increases were partially offset by unfavourable foreign exchange associated with the translation of US dollar-denominated revenue and the flow through in customer rates of lower overall energy supply costs at FortisBC Energy.

Earnings
The decrease in earnings was driven by lower earnings at ITC, due to the one-time remeasurement of deferred income tax assets and liabilities as a result of U.S. Tax Reform, partially offset by higher earnings at Aitken Creek associated with unrealized gains on the mark-to-market of derivatives.

Basic Earnings per Common Share
Basic earnings per common share were $0.17 lower compared to the fourth quarter of 2016. The impact of the above noted items on net earnings attributable to common equity shareholders were also impacted by an increase in the weighted average number of common shares outstanding, as a result of shares issued to finance a portion of the acquisition of ITC and the Corporation's dividend reinvestment and other share plans.

Summary of Consolidated Cash Flows			
Fourth Quarters Ended December 31			
($ millions)	**2017**	2016	Variance
Cash, Beginning of Period	**252**	301	(49)
Cash Provided by (Used in):			
Operating Activities	**766**	475	291
Investing Activities	**(882)**	(5,187)	4,305
Financing Activities	**191**	4,685	(4,494)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**—**	(5)	5
Cash, End of Period	**327**	269	58

Cash flow from operating activities was $291 million higher quarter over quarter. The increase was primarily due to favourable changes in working capital, higher cash earnings, driven by ITC, and the Corporation's acquisition-related transaction costs in the fourth quarter of 2016. The increase was partially offset by unfavourable changes in long-term regulatory deferrals.

Cash used in investing activities was $4,305 million lower quarter over quarter. The decrease was primarily due to the acquisition of ITC in October 2016 for a net cash consideration of approximately $4.5 billion (US $3.5 billion), partially offset by higher capital spending at most of the Corporation's regulated utilities.

Cash provided by financing activities was $4,494 million lower quarter over quarter. The decrease was primarily due to financing activities associated with the acquisition of ITC in the fourth quarter of 2016, higher repayments of long-term debt and changes in short-term borrowings. The increase was partially offset by higher proceeds from the issuance of long-term debt at the Corporation's regulated utilities, driven by ITC, and higher net borrowings under committed credit facilities.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth quarterly information for each of the eight quarters ended March 31, 2016 through December 31, 2017. The quarterly information has been obtained from the Corporation's unaudited condensed consolidated interim 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		**Net Earnings Attributable to Common Equity Shareholders**	**Earnings per Common Share**	
Quarter Ended	**Revenue** *($ millions)*	*($ millions)*	**Basic** *($)*	**Diluted** *($)*
December 31, 2017	2,111	134	0.32	0.31
September 30, 2017	1,901	278	0.66	0.66
June 30, 2017	2,015	257	0.62	0.62
March 31, 2017	2,274	294	0.72	0.72
December 31, 2016	2,053	189	0.49	0.49
September 30, 2016	1,528	127	0.45	0.45
June 30, 2016	1,485	107	0.38	0.38
March 31, 2016	1,772	162	0.57	0.57

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions net of the associated acquisition-related transaction costs, and seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity and gas demand, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel, purchased power and natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric distribution utilities in the United States are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

December 2017/December 2016: Net earnings attributable to common equity shareholders were $134 million, or $0.32 per common share, for the fourth quarter of 2017 compared to earnings of $189 million, or $0.49 per common share, for the fourth quarter of 2016. A discussion of the variances in financial results for the fourth quarter is provided in the "Fourth Quarter Results" section of this MD&A.

September 2017/September 2016: Net earnings attributable to common equity shareholders were $278 million, or $0.66 per common share, for the third quarter of 2017 compared to earnings of $127 million, or $0.45 per common share, for the third quarter of 2016. The increase was driven by earnings of $89 million at ITC, which was acquired in October 2016. The increase for the quarter was also due to: (i) lower Corporate and Other expenses, primarily due to the receipt of a break fee, net of related transaction costs, of $24 million associated with the termination of the Waneta Dam purchase agreement recognized in the third quarter of 2017, and $19 million in acquisition-related transactions costs associated with ITC recognized in the third quarter of 2016; (ii) higher earnings from Aitken Creek related to the unrealized gain on the mark-to-market of derivatives quarter over quarter; (iii) strong performance at UNS Energy, largely due to the impact of the rate case settlement in 2017 and FERC-ordered refunds of $7 million in the third quarter of 2016; (iv) higher earnings at FortisAlberta due to an increase in capital tracker revenue; and (v) a lower loss at FortisBC Energy due to higher AFUDC and lower operating expenses. The increase was partially offset by: (i) higher finance charges associated with the acquisition of ITC; (ii) the favourable settlement of Springerville Unit 1 matters at UNS Energy in the third quarter of 2016; (iii) unfavourable foreign exchange associated with the translation of US dollar-denominated earnings; (iv) lower contribution from the Caribbean, mainly due to the impact of Hurricane Irma and lower equity income from Belize Electricity; and (v) business development costs related to the Wataynikaneyap Power Project.

June 2017/June 2016: Net earnings attributable to common equity shareholders were $257 million, or $0.62 per common share, for the second quarter of 2017 compared to earnings of $107 million, or $0.38 per common share, for the second quarter of 2016. The increase was driven by earnings of $93 million at ITC, acquired in October 2016. The increase for the quarter was also due to: (i) strong performance at UNS Energy, largely due to the impact of the rate case settlement and higher electricity sales; (ii) lower Corporate and Other expenses, primarily due to $22 million in acquisition-related transaction costs associated with ITC recognized in the second quarter of 2016; (iii) higher earnings from Aitken Creek related to the unrealized gain on the mark-to-market of derivatives quarter over quarter; and (iv) favourable foreign exchange associated with the translation of US dollar-denominated earnings. The increase was partially offset by higher finance charges associated with the acquisition of ITC.

March 2017/March 2016: Net earnings attributable to common equity shareholders were $294 million, or $0.72 per common share, for the first quarter of 2017 compared to earnings of $162 million, or $0.57 per common share, for the first quarter of 2016. The increase was driven by earnings of $91 million at ITC, acquired in October 2016. The increase was also due to: (i) strong performance at UNS Energy, due to the favourable settlement of matters pertaining to FERC-ordered transmission refunds of $7 million, after-tax, in January 2017 compared to $11 million, after-tax, in FERC-ordered transmission refunds in the first quarter of 2016, and higher retail rates as approved pursuant to its 2017 general rate case; (ii) acquisition-related transactions costs associated with ITC recognized in Corporate and Other expenses in the first quarter of 2016; (iii) contribution from Aitken Creek, including an after-tax $6 million unrealized gain on the mark-to-market of derivatives; and (iv) the timing of quarterly revenue and operating expenses as compared to the same period in 2016 and higher AFUDC at FortisBC Energy. The increase was partially offset by: (i) lower contribution from FortisAlberta, mainly due to lower customer rates and higher operating expenses; (ii) higher finance charges at Corporate and Other associated with the acquisitions of ITC and Aitken Creek; and (iii) unfavourable foreign exchange associated with US dollar-denominated earnings.

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

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities laws. As at December 31, 2017, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the President and Chief Executive Officer ("CEO") and the Executive Vice President, Chief Financial Officer ("CFO"), of the effectiveness of the Corporation's disclosure controls and procedures, as defined in the applicable Canadian and United States securities laws. Based on that evaluation, the CEO and CFO concluded that such disclosure controls and procedures are effective as at December 31, 2017.

Internal Control Over Financial Reporting

Internal control over financial reporting is designed by, or under the supervision of, the Corporation's CEO and CFO and effected by the Corporation's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's internal control over financial reporting as at December 31, 2017, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as at December 31, 2017, the Corporation's internal control over financial reporting was effective.

During the year ended December 31, 2017, there have been no changes in the Corporation's internal control over financial reporting that have materially affected, or is reasonably likely to materially affect, the Corporation's internal control over financial reporting.

OUTLOOK

Fortis expects its annual earnings per share will be reduced by approximately 3%, as a result of U.S. Tax Reform and interest being deducted at the lower tax rate of 21%. Under U.S. Tax Reform, regulated utilities are being treated differently than most businesses because they are exempt from both the limitation on interest deductibility and the immediate expensing of capital investments, referred to as bonus depreciation. Additionally, near-term cash flows of the Corporation's U.S. regulated utilities will be reduced due to the lower corporate tax rate.

Going forward, the impact of U.S. Tax Reform will increase rate base growth over the five-year period to 2022 by approximately 50 basis points. Consequently, the compound annual growth in rate base over the next five years is expected to increase to 5%.

Fortis is focused on executing the five-year capital expenditure program and securing further organic growth opportunities at its subsidiaries, which may be funded through debt raised at the utilities, cash from operations, common equity contributions from the dividend reinvestment plan and the newly approved ATM Program. Fortis expects the long-term sustainable growth in rate base to support continuing growth in earnings and dividends.

Fortis has targeted average annual dividend growth of approximately 6% through 2022. 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 program, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

OUTSTANDING SHARE DATA

As at February 14, 2018, the Corporation had issued and outstanding 421.1 million common shares; 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 were converted as at February 14, 2018 is approximately 3.7 million.

Additional information can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov. The information contained on, or accessible through, any of these websites is not incorporated by reference into this document.