

## Management Discussion and Analysis

For the year ended December 31, 2016  
Dated February 15, 2017

### CONTENTS

Forward-Looking Information .....	1	Liquidity and Capital Resources .....	24
Corporate Overview .....	3	Summary of Consolidated Cash Flows .....	24
Corporate Strategy .....	5	Contractual Obligations .....	27
Key Trends, Risks and Opportunities .....	6	Capital Structure .....	29
Significant Items .....	8	Credit Ratings .....	30
Summary Financial Highlights .....	9	Capital Expenditure Program .....	30
Consolidated Results of Operations .....	11	Additional Investment Opportunities.....	33
Segmented Results of Operations .....	13	Cash Flow Requirements .....	35
Regulated Utilities .....	13	Credit Facilities .....	35
Regulated Electric & Gas Utilities – United States..	14	Off-Balance Sheet Arrangements .....	37
ITC .....	14	Business Risk Management .....	37
UNS Energy .....	15	Changes in Accounting Policies.....	49
Central Hudson.....	15	Future Accounting Pronouncements .....	50
Regulated Gas & Electric Utilities – Canadian .....	16	Financial Instruments .....	51
FortisBC Energy .....	16	Critical Accounting Estimates .....	54
FortisAlberta .....	17	Related-Party and Inter-Company Transactions.....	59
FortisBC Electric.....	17	Selected Annual Financial Information .....	60
Eastern Canadian Electric Utilities .....	18	Fourth Quarter Results .....	62
Regulated Electric Utilities – Caribbean .....	18	Summary of Quarterly Results .....	64
Non-Regulated.....	19	Management’s Evaluation of Disclosure Controls	
Non-Regulated – Energy Infrastructure .....	19	and Procedures and Internal Controls over	
Non-Regulated – Non-Utility .....	19	Financial Reporting.....	66
Corporate and Other .....	20	Outlook .....	66
Regulatory Highlights .....	21	Outstanding Share Data .....	66
Consolidated Financial Position.....	23		

### FORWARD-LOOKING INFORMATION

The following Fortis Inc. (“Fortis” or the “Corporation”) Management Discussion and Analysis (“MD&A”) has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. The MD&A should be read in conjunction with the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2016. Financial information for 2016 and comparative periods contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States (“US GAAP”) and is presented in Canadian dollars unless otherwise specified.

*Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws including the Private Securities Litigation Reform Act of 1995. Forward-looking statements 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 statements, which include, without limitation: the expectation that the acquisition of ITC Holdings Corp. (“ITC”) will be accretive to earnings per common share in 2017; the Corporation’s business model provides superior transparency and best serves the interest of customers; target average annual dividend growth through 2021; the Corporation’s forecast midyear rate base through 2021; expected compound annual growth rate in rate base through 2019; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the Corporation’s forecast gross consolidated and segmented capital expenditures for 2017 and from 2017 to 2021; the nature, timing and expected costs of certain capital projects including, without limitation, expansions of the Tilbury liquefied natural gas (“LNG”) facility, ITC Multi-Value Projects, the 34.5 to 69 kilovolt Conversion Project, the Gas Main Replacement Program, the Lower Mainland System Upgrade, the Pole Management Program, and additional opportunities including the pipeline expansion to the Woodfibre LNG site, the Wataynikaneyap Project and the Lake Erie Connector Project; the expectation that the Corporation’s significant capital expenditure program will support continuing growth in earnings and dividends; expected consolidated fixed term debt maturities and repayments in 2017 and over the next five years;*

the expectation that the Corporation and its utilities will have reasonable access to long-term capital in 2017; the expectation that the Corporation will repay borrowings under the equity bridge facility using proceeds from a common equity offering in 2017; 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 cash from operations, borrowings under credit facilities, equity injections from Fortis and long term debt offerings; 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 and advances from minority investors; the expectation that borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends; 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 intent of management to refinance certain borrowings under Corporation's and subsidiaries' long-term committed credit facilities with long-term permanent financing; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout 2017; the expectation that the Corporation may enter into forward foreign exchange contracts and utilize certain derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past; the expectation that long-term debt will not be settled prior to maturity; the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations; Tucson Electric Power Company's expected share of mine reclamation costs; the expectation that any increases or decreases in defined benefit net pension cost at the regulated utilities for 2017 will be recovered from or refunded to customers in rates; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.

Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking statements, 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 including natural gas related infrastructure and generation; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; no significant 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 Caribbean 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 statements involve 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 statements. These factors should be considered carefully and undue reliance should not be placed on the forward-looking statements. 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 2017 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; uncertainty of the impact a continuation of a low interest rate environment may have on the allowed rate of return on common shareholders' equity at the Corporation's regulated utilities; the impact of fluctuations in foreign exchange rates; uncertainty related to proposed tax reform in the United States; risk associated with the impacts of less favourable economic conditions on the Corporation's results of operations; risk that the expected benefits of the acquisition of ITC may fail to materialize, or may not occur within the time periods anticipated; risk associated with the Corporation's ability 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 2017 capital expenditures plan, 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 qualified in its entirety by the above cautionary statements and, except as required by law, Fortis disclaims any intention or obligation to update or revise any forward-looking statements, 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 total assets of approximately \$48 billion and fiscal 2016 revenue of \$6.8 billion. More than 8,000 employees of the Corporations serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. In 2016 the Corporation's electricity systems met a combined peak demand of 33,021 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,586 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 and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") 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 utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated energy infrastructure, which is treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

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

## REGULATED UTILITIES

### Electric & Gas Utilities - United States

- a. *ITC*: Primarily comprised of ITC Holdings Corp. ("ITC Holdings") and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITC Transmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC ("ITC Great Plains"), (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.

ITC owns and operates high-voltage transmission lines serving a system peak load exceeding 26,000 MW along approximately 25,000 kilometres in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from approximately 570 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”).

TEP, UNS Energy’s largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 420,000 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 95,000 retail customers in Arizona’s Mohave and Santa Cruz counties. TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,994 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2016, approximately 47% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility, serving approximately 154,000 retail customers in Arizona’s Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

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

### Gas & Electric Utilities - Canadian

- a. *FortisBC Energy*: FortisBC Energy Inc. (“FortisBC Energy” or “FEI”) is the largest distributor of natural gas in British Columbia, serving approximately 994,000 customers in more than 135 communities. Major areas served by the Company are the Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI’s Southern Crossing pipeline, from Alberta.
- b. *FortisAlberta*: FortisAlberta Inc. (“FortisAlberta”) owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 549,000 customers. 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 electric utility operating in the southern interior of British Columbia, serving approximately 170,000 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”) and FortisOntario Inc. (“FortisOntario”). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 264,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island, serving approximately 79,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 145 MW. FortisOntario is comprised of three electric utilities that provide service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario.

### Electric Utilities – Caribbean

The Electric Utilities – Caribbean segment includes the Corporation’s approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. (“Caribbean Utilities”) (December 31, 2015 - 60%), Fortis Turks and Caicos, and the Corporation’s 33% equity investment in Belize Electricity Limited (“Belize Electricity”). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 29,000 customers. The Company has an

installed diesel-powered generating capacity of 161 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (“TSX”) (TSX: CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities serving approximately 15,000 customers on certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

### **NON-REGULATED - ENERGY INFRASTRUCTURE**

Non-Regulated - Energy Infrastructure is 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 (“ACGS”), 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 (“Walden”) and in 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario.

### **NON-REGULATED - NON-UTILITY**

The Non-Utility segment previously included Fortis Properties Corporation (“Fortis Properties”). Fortis Properties completed the sale of its commercial real estate and hotel assets in 2015.

### **CORPORATE AND OTHER**

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments. The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. (“FHI”), CH Energy Group, Inc. (“CH Energy Group”), and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. (“FAES”). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

### **CORPORATE STRATEGY**

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 wires and gas 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, 2016, earnings per common share of Fortis grew at a compound annual growth rate of 5.2%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 7.3%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 5.7% and 4.7%, respectively, over the same period.

The Corporation is committed to achieving long-term sustainable growth in rate base, assets and earnings resulting from investment in existing utility operations. Management remains focused on executing the consolidated capital program and pursuing additional investment opportunities within existing service territories. Fortis has also demonstrated its ability to acquire regulated utilities in North America. The Corporation’s standalone operating model positions it well for future investment opportunities in existing and new franchise areas. The Corporation maintains a small head office and its utilities are operated 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 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.

The desire for cleaner energy continues to gain momentum throughout North America. Government and regulatory policy in Canada and the United States is being directed at environmental protection, requiring utilities to develop and execute plans to cost-effectively reduce carbon emissions. Such environmental 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.

Technological development, particularly in the area of distributed generation, continues to play a significant role in the transformation of the utility industry. The move towards cleaner energy has created an increase in the use of distributed generation, particularly solar generation, by customers. This creates a shift in the role of the utility to be a distribution grid network integrator and facilitator, and will require utilities of the future to be able to dispatch and control customer distributed energy resources and integrate those sources into the grid. Distributed generation creates an opportunity for investment in distribution automation, management systems and other grid-modernizing technology. It also presents challenges in the rate designs for distributed generation and other customers to ensure fairness in pricing across all customers. The Corporation's utilities are working with their regulators to address such rate design issues.

Customer expectations on grid resiliency continue to increase. This expectation, in combination with the aging infrastructure of electric and gas utilities in North America, creates an opportunity for increased capital investment. The construction of new infrastructure, such as pipelines and transmission lines, is becoming increasingly challenged by the public, particularly environmental activists. Constructive and collaborative relationships with regulators, policy makers and customers will be critical to the continued long-term success of utilities.

Industry consolidation, particularly in the United States, is continuing with the number of investor-owned utilities decreasing. Consolidation is being driven by a low cost of capital environment, and the need for utilities to sustain earnings growth in an economy that is characterized by low sales growth. The Corporation's proven track record of successfully acquiring and integrating utilities, as well as its standalone business operating model, positions it well in this environment.

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. Leveraging those relationships to remain in front of these evolving challenges will be essential to meeting the industry challenges.

**Regulation:** The Corporation's key business risk is regulation. Each of the Corporation's utilities is subject to regulation by the regulatory body in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level. Commitment by the Corporation's utilities to provide safe and reliable service, operational excellence and promote positive customer and regulatory relations is important to ensure supportive regulatory relationships and obtain full cost recovery and competitive returns for the Corporation's shareholders.

In 2016, the Corporation's utilities made significant progress on a number of key regulatory proceedings, providing stability for the utilities in the near term. In addition to the proceedings noted below, Generic Cost of Capital ("GCOC") Proceedings concluded in British Columbia and Alberta in the second half of 2016.

In February 2017, the ACC issued a Rate Order in TEP's general rate application ("GRA") filed in November 2015, based on a historical test year ended June 30, 2015. The Rate Order approved rates effective on or before March 1, 2017. The provisions of the Rate Order include, but are not limited to an

increase in non-fuel base revenue of US\$81.5 million, an allowed ROE of 9.75%, and a common equity component of capital structure of approximately 50%.

In September 2016, ITC received an order from the United States Federal Energy Regulatory Commission (“FERC”) regarding one of two third-party complaints requesting that FERC find the Midcontinent Independent System Operator (“MISO”) regional base ROE for all MISO transmission owners, including ITC’s MISO-member regulated utilities, to no longer be just and reasonable. The two complaints cover the period from November 2013 through May 2016. The FERC order on the first complaint set the base ROE at 10.32%, with a maximum ROE of 11.35%, and established that those rates are to be used prospectively until a new approved rate is established for the second complaint. In June 2016 the presiding Administrative Law Judge (“ALJ”) issued an initial decision on the second complaint, which recommended a base ROE of 9.70%, with a maximum ROE of 10.68%, which is a recommendation to FERC. A decision from FERC on the second complaint is expected in 2017.

The utilities continue to be actively engaged with all 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 2016 was \$24.3 billion, including ITC. Over the five-year period through 2021, the Corporation’s capital program is expected to be approximately \$13 billion. This investment in energy infrastructure is expected to increase rate base to almost \$30 billion in 2021 and produce a five-year compound annual growth rate in rate base of approximately 4%. The three-year compound annual growth rate in rate base through 2019 is expected to be over 5%, reflecting greater visibility in capital expenditures in the next three years. Fortis expects this capital investment to support growth in earnings and dividends.

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

**Access to Capital and Liquidity:** The Corporation’s regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities usually issue debt at terms ranging between 5 and 40 years. As at December 31, 2016, almost 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 \$680 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately \$6.0 billion in credit facilities, of which approximately \$3.7 billion was unused as at December 31, 2016. 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 2017.

**Dividend Increases:** Dividends paid per common share increased to \$1.53 in 2016. In 2016 Fortis increased its quarterly dividend per common share by almost 7% to \$0.40 per quarter, or \$1.60 on an annualized basis. This continues the Corporation’s record of raising its annualized dividend to common shareholders for 43 consecutive years, the record for a public corporation in Canada.

Fortis also extended its dividend guidance, targeting average annual dividend per common share growth of 6% through 2021. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its \$13 billion five-year capital expenditure plan, and management’s continued confidence in the strength of the Corporation’s diversified portfolio of assets and record of operational excellence.

## SIGNIFICANT ITEMS

**Acquisition of ITC:** On October 14, 2016, Fortis and GIC acquired all of the outstanding common shares of ITC for an aggregate purchase price of approximately US\$11.8 billion (\$15.7 billion) on closing, including approximately US\$4.8 billion (\$6.3 billion) of ITC consolidated indebtedness. ITC is now a subsidiary of Fortis, with an affiliate of GIC owning a 19.9% minority interest in ITC. For additional information on ITC, refer to the “Segmented Results of Operations - Regulated Electric & Gas Utilities - United States” section of this MD&A.

Under the terms of the transaction, ITC shareholders received US\$22.57 in cash and 0.7520 of a Fortis common share per ITC share, representing total consideration of approximately US\$7.0 billion (\$9.4 billion). The net cash consideration totalled approximately US\$3.5 billion (\$4.7 billion) and was financed using: (i) net proceeds from the issuance of US\$2.0 billion unsecured notes in October 2016; (ii) net proceeds from GIC’s US\$1.228 billion minority investment, which includes a shareholder note of US\$199 million; and (iii) drawings of approximately US\$404 million (\$535 million) under the Corporation’s non-revolving term senior unsecured equity bridge credit facility. On October 14, 2016, approximately 114.4 million common shares of Fortis were issued to shareholders of ITC, representing share consideration of approximately US\$3.5 billion (\$4.7 billion), based on the closing price for Fortis common shares of \$40.96 and the closing foreign exchange rate of US\$1.00=CAD\$1.32 on October 13, 2016. The financing of the acquisition was structured to allow Fortis to maintain investment-grade credit ratings.

Fortis and ITC shareholders approved the acquisition at shareholder meetings held in May and June 2016, respectively. All required regulatory, state and federal approvals associated with the acquisition were received prior to closing. In connection with the acquisition, on May 17, 2016, Fortis became a United States Securities and Exchange Commission (“SEC”) registrant and, on October 14, 2016, commenced trading its common shares on the New York Stock Exchange. Fortis continues to list its shares on the TSX.

Acquisition-related expenses totalling \$118 million (\$90 million after tax) were recognized in earnings in 2016 (2015 - \$10 million (\$7 million after tax)). For additional details on the acquisition-related expenses refer to the “Segmented Results of Operations - Corporate and Other” section of this MD&A. Earnings of ITC from the date of acquisition were reduced by US\$21 million (\$27 million) in after-tax expenses associated with the accelerated vesting of the Company’s stock-based compensation awards as a result of the acquisition, of which the Corporation’s share was US\$17 million (\$22 million).

### **Acquisition of Aitken Creek Gas Storage Facility**

On April 1, 2016, Fortis acquired Aitken Creek from Chevron Canada Properties Ltd. for approximately \$349 million (US\$266 million), plus the cost of working gas inventory. The net cash purchase price was initially financed through US dollar-denominated borrowings under the Corporation’s committed revolving credit facility.

ACGS 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. The facility is an integral part of western Canada’s natural gas transmission network. ACGS also owns 100% of the North Aitken Creek gas storage site which offers future expansion potential. The financial results of ACGS have been included in the Corporation’s consolidated results from the date of acquisition.

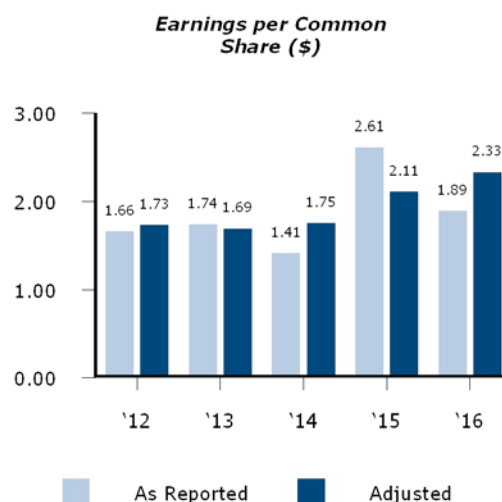
## SUMMARY FINANCIAL HIGHLIGHTS

For the Years Ended December 31	2016	2015	Variance
Net Earnings Attributable to Common Equity Shareholders (\$ millions)	585	728	(143)
Basic Earnings per Common Share (\$)	1.89	2.61	(0.72)
Adjusted Basic Earnings per Common Share (\$) <sup>(1)</sup>	2.33	2.11	0.22
Weighted Average Number of Common Shares Outstanding (millions)	308.9	278.6	30.3
Cash Flow from Operating Activities (\$ billions)	1.9	1.7	0.2
Dividends Paid per Common Share (\$)	1.53	1.40	0.13
Dividend Payout Ratio (%)	81.0	53.6	27.4
Total Assets (\$ billions)	47.9	28.8	19.1
Gross Capital Expenditures (\$ billions)	2.1	2.2	(0.1)
Common Shares Issued on Business Acquisition (\$ billions)	4.7	—	4.7
Long-Term Debt Offerings (\$ billions)	4.1	1.0	3.1

<sup>(1)</sup> 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.

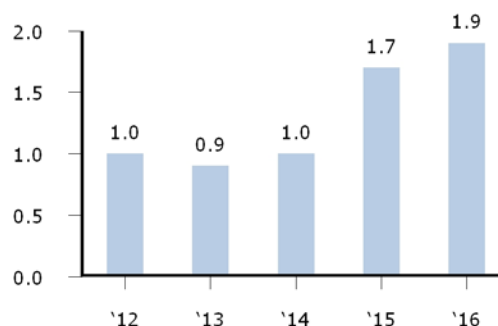
**Net Earnings Attributable to Common Equity Shareholders:** Fortis achieved net earnings attributable to common equity shareholders of \$585 million in 2016 compared to \$728 million in 2015. Results reflect the acquisition of ITC in 2016, including acquisition-related expenses, and gains on the sale of non-core assets in 2015. On an adjusted basis, net earnings attributable to common equity shareholders for 2016 were \$721 million, an increase of \$132 million, or approximately 22%, compared to 2015. The increase was driven by the acquisition of ITC, strong performance at most of the Corporation's regulated utilities, contribution from Aitken Creek and favourable foreign exchange associated with US dollar-denominated earnings. A reconciliation of adjusted net earnings attributable to common equity shareholders and adjusted earnings per common share is provided in "Consolidated Results of Operations" section of this MD&A.

**Basic Earnings per Common Share:** Basic earnings per common share were \$1.89 in 2016 compared to \$2.61 in 2015. On an adjusted basis, basic earnings per common share were \$2.33 for 2016, an increase of \$0.22, or 10%, compared to 2015. The increase was driven by accretion associated with the acquisition of ITC in October 2016, including the impact of finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding. The impact of the other above-noted items on adjusted earnings attributable to common equity shareholders were partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment and share plans.



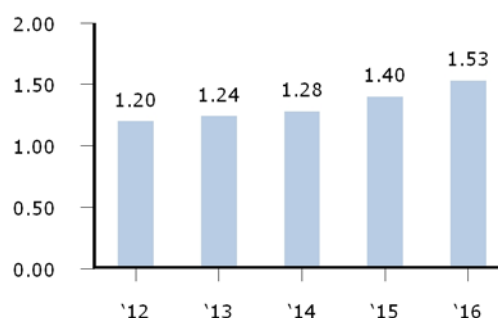
**Cash Flow from Operating Activities:** Cash flow from operating activities was \$1.9 billion for 2016, an increase of \$0.2 billion, or 13%, compared to 2015. The increase was primarily due to higher cash earnings at the regulated utilities, driven by the acquisition of ITC, partially offset by the Corporation's acquisition-related expenses. Favourable changes in long-term regulatory deferrals were partially offset by unfavourable changes in working capital.

**Cash Flow from Operating Activities (\$ billions)**



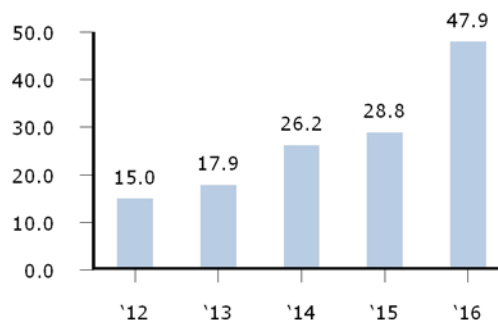
**Dividends:** Dividends paid per common share increased to \$1.53 in 2016, 9% higher than \$1.40 in 2015. During 2016 Fortis increased its quarterly dividend per common share by almost 7% to \$0.40 per quarter. The Corporation's dividend payout ratio was 81.0% in 2016 compared to 53.6% in 2015. On an adjusted basis, the dividend payout ratio was 65.7% in 2016 compared to 66.4% in 2015.

**Dividends Paid per Common Share (\$)**



**Total Assets:** Total assets increased 66% to approximately \$47.9 billion at the end of 2016 compared to approximately \$28.8 billion at the end of 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.

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



**Gross Capital Expenditures:** Consolidated capital expenditures, before customer contributions, were \$2.1 billion in 2016 compared to \$2.2 billion in 2015. Consolidated capital expenditures for 2016 were higher than the Corporation's forecast of \$1.9 billion. The higher-than-forecast capital investments were driven by capital spending at ITC from the date of acquisition. 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:** 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 (US\$3.5 billion). The net cash consideration totalled approximately \$4.7 billion (US\$3.5 billion) and was financed using: (i) net proceeds from the issuance of US\$2.0 billion unsecured notes in October 2016; (ii) net proceeds from GIC's US\$1.228 billion minority investment, which includes a shareholder note of US\$199 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 addition to financing associated with the acquisition of ITC, the Corporation and its regulated utilities raised over \$1.5 billion in long-term debt in 2016, largely in support of energy infrastructure investment, including the acquisition of Aitken Creek in April 2016, and for regularly scheduled debt repayments. In September 2016, the Corporation redeemed all of the First Preference Shares, Series E for \$200 million.

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)	2016	2015	Variance
Revenue	6,838	6,757	81
Energy Supply Costs	2,341	2,591	(250)
Operating Expenses	2,031	1,874	157
Depreciation and Amortization	983	873	110
Other Income (Expenses), Net	53	197	(144)
Finance Charges	678	553	125
Income Tax Expense	145	223	(78)
<b>Net Earnings</b>	<b>713</b>	840	(127)
Net Earnings Attributable to:			
Non-Controlling Interests	53	35	18
Preference Equity Shareholders	75	77	(2)
Common Equity Shareholders	585	728	(143)
<b>Net Earnings</b>	<b>713</b>	840	(127)

### Revenue

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.

### Energy Supply Costs

The decrease in energy supply costs was mainly due to lower overall commodity costs. The decrease was partially offset by energy supply costs at Aitken Creek and unfavourable 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, including acquisition-related expenses, operating expenses at Aitken Creek, unfavourable foreign exchange associated with the translation of US dollar-denominated operating expenses and general inflationary and employee-related cost increases. The increase was partially offset by a decrease in non-utility operating expenses due to the sale of commercial real estate and hotel assets in 2015.

### Depreciation and Amortization

The increase in depreciation and amortization was primarily due to the acquisition of ITC, continued investment in energy infrastructure at the Corporation's regulated utilities, depreciation at Aitken Creek, and unfavourable foreign exchange associated with the translation of US dollar-denominated depreciation. The increase was partially offset by lower non-utility depreciation due to the sale of commercial real estate and hotel assets in 2015.

### Other Income (Expenses), Net

The decrease in other income, net of expenses, was primarily due to a net gain of approximately \$109 million (\$101 million after tax), net of expenses, related to the sale of commercial real estate and hotel assets in 2015 and a gain of approximately \$56 million (\$32 million after tax), net of expenses and foreign exchange impacts, on the sale of non-regulated generation assets in 2015.

### Finance Charges

The increase in finance charges was primarily due to the acquisition of ITC, including acquisition-related fees associated with the Corporation's acquisition credit facilities and deal-contingent interest rate swap contracts, and interest expense on debt issued to complete the financing of the acquisition. The impact of unfavourable foreign exchange associated with the translation of US-dollar denominated interest expense also contributed to the increase.

### Income Tax Expense

The decrease in income tax expense was primarily due to lower earnings before income taxes, mainly due to acquisition-related expenses in 2016 and the net gains on the sale of commercial real estate, hotel and non-regulated generation assets in 2015.

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

Fortis supplements the use of US GAAP financial measures with non-US GAAP financial measures, including adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share. The Corporation refers to these measures as non-US GAAP financial measures since they are not required by, or presented in accordance with, US GAAP.

The Corporation defines: (i) adjusted net earnings attributable to common equity shareholders as net earnings attributable to common equity shareholders plus or minus items that management believes help investors better evaluate results of operations; and (ii) adjusted basic earnings per common share as adjusted net earnings attributable to common equity shareholders divided by the weighted average number of common shares outstanding. 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.

The following table provides a reconciliation of the non-US GAAP financial measures and each of the adjusting items are discussed in the segmented results of operations for the respective reporting segments. The adjusting items do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. Therefore, these adjusting items may not be comparable with similar measures presented by other companies.

<b>Non-US GAAP Reconciliation</b>			
Years Ended December 31			
<i>(\$ millions, except for common share data)</i>			
	<b>2016</b>	2015	Variance
Net Earnings Attributable to Common Equity Shareholders	<b>585</b>	728	(143)
Adjusting Items:			
ITC -			
Accelerated vesting of stock-based compensation awards	<b>22</b>	—	22
UNS Energy -			
FERC ordered transmission refunds	<b>18</b>	—	18
FortisAlberta -			
Capital tracker revenue adjustment for 2013 and 2014	—	(9)	9
Non-Regulated - Energy Infrastructure -			
Gain on sale of non-regulated generation assets	—	(32)	32
Unrealized loss on mark-to-market of derivatives	<b>6</b>	—	6
Non-Utility -			
Net gain on sale of commercial real estate and hotel assets	—	(101)	101
Corporate and Other -			
Acquisition-related expenses and fees	<b>90</b>	7	83
Foreign exchange gain	—	(13)	13
Loss on settlement of expropriation matters	—	9	(9)
Adjusted Net Earnings Attributable to Common Equity Shareholders	<b>721</b>	589	132
Adjusted Basic Earnings per Common Share (\$)	<b>2.33</b>	2.11	0.22
Weighted Average Number of Common Shares Outstanding <i>(# millions)</i>	<b>308.9</b>	278.6	30.3

### Adjusted Net Earnings Attributable to Common Equity Shareholders

The increase in adjusted net earnings attributable to common equity shareholders was driven by earnings contribution of \$81 million at ITC from the date of acquisition in October 2016. The increase was also due to: (i) 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 allowance for funds used during construction ("AFUDC") at FortisBC Energy, and stronger performance from the Caribbean; (ii) favourable foreign exchange associated with US dollar-denominated earnings; and (iii) contribution from Aitken Creek and higher earnings at the Waneta Expansion, which commenced production in early April 2015. The increase was partially offset by: (i) higher Corporate and Other expenses, largely due to finance charges associated with the acquisition of ITC; (ii) the sale of commercial real estate and hotel assets in 2015; and (iii) lower earnings at FortisAlberta mainly due to lower average energy consumption and higher operating expenses.

### Adjusted Basic Earnings per Common Share

The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of ITC, including the impact of finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding. The impact of the other above-noted items on adjusted earnings attributable to common equity shareholders were partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment and share plans.

## SEGMENTED RESULTS OF OPERATIONS

<b>Segmented Net Earnings Attributable to Common Equity Shareholders</b>			
Years Ended December 31			
(\$ millions)			
	2016	2015	Variance
<b>Regulated Electric &amp; Gas Utilities - United States</b>			
ITC	59	—	59
UNS Energy	199	195	4
Central Hudson	70	58	12
	<b>328</b>	253	75
<b>Regulated Gas &amp; Electric Utilities - Canadian</b>			
FortisBC Energy	151	140	11
FortisAlberta	121	138	(17)
FortisBC Electric	54	50	4
Eastern Canadian	64	62	2
	<b>390</b>	390	—
<b>Regulated Electric Utilities - Caribbean</b>			
	46	34	12
Non-Regulated - Energy Infrastructure	60	77	(17)
Non-Regulated - Non-Utility	—	114	(114)
Corporate and Other	(239)	(140)	(99)
<b>Net Earnings Attributable to Common Equity Shareholders</b>	<b>585</b>	728	(143)

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

## REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2016 earnings from regulated utilities represented approximately 93% (2015 – 92%, excluding the gains on sale of non-core assets) of the Corporation's earnings from its operating segments (excluding Corporate and Other segment expenses). Total regulated assets represented 97% of the Corporation's total assets as at December 31, 2016 (December 31, 2015 – 96%).

## REGULATED ELECTRIC & GAS UTILITIES – UNITED STATES

Regulated Electric & Gas Utilities - United States earnings for 2016 were \$328 million (2015 - \$253 million), which represented approximately 43% (2015 - 37%) of the Corporation's total regulated earnings. Total segment assets were approximately \$30.1 billion as at December 31, 2016 (December 31, 2015 - \$12.1 billion), which represented approximately 65% of the Corporation's total regulated assets as at December 31, 2016 (December 31, 2015 - 44%). The increases were driven by the acquisition of ITC.

### ITC

<b>Financial Highlights</b> <sup>(1)</sup>	
Years Ended December 31	<b>2016</b>
Average US:CAD Exchange Rate <sup>(2)</sup>	<b>1.34</b>
Revenue (\$ millions)	<b>334</b>
Earnings (\$ millions)	<b>59</b>

<sup>(1)</sup> Financial results of ITC are from October 14, 2016, the date of acquisition. For additional information on the acquisition of ITC, refer to the "Significant Items - Acquisition of ITC" section of this MD&A. 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.

<sup>(2)</sup> The reporting currency of ITC is the US dollar. The average US:CAD exchange rate is from the date of acquisition.

#### Revenue

ITC derives the majority of its revenue from providing transmission, scheduling, control and dispatch services over its transmission systems to its customers and other entities that provide electricity to end-use customers. Revenue was US\$250 million (\$334 million) from the date of acquisition. On an annual basis, revenue was US\$1,125 million for 2016 compared to US\$1,045 million for 2015. Revenue for both years was reduced due to the recognition of refund liabilities, largely related to base ROE complaints, which totalled US\$80 million for 2016 and US\$115 million for 2015. The refund liabilities for both years included amounts related to prior periods. Excluding the impact of the refund liabilities, ITC's revenue increased by US\$45 million, driven by higher network revenue and regional cost-sharing revenue largely due to rate base growth.

#### Earnings

Earnings contribution from ITC was US\$44 million (\$59 million) from the date of acquisition. Earnings of ITC from the date of acquisition were reduced by US\$21 million (\$27 million) in after-tax expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition, of which the Corporation's share was US\$17 million (\$22 million).

On an annual basis, earnings of ITC were US\$246 million for 2016 compared to US\$242 million for 2015. Earnings for 2016 were reduced by after-tax acquisition-related expenses of US\$69 million, including the accelerated vesting of the Company's stock-based compensation awards, as discussed above. Excluding the acquisition-related expenses, earnings of ITC increased by US\$73 million. The increase was driven by rate base growth, higher AFUDC, and lower income tax expense.

## UNS ENERGY

<b>Financial Highlights</b>			
Years Ended December 31	2016	2015	Variance
Average US:CAD Exchange Rate <sup>(1)</sup>	1.33	1.28	0.05
Electricity Sales ( <i>gigawatt hours ("GWh")</i> )	14,387	15,366	(979)
Gas Volumes ( <i>petajoules ("PJ")</i> )	13	13	—
Revenue ( <i>\$ millions</i> )	2,002	2,034	(32)
Earnings ( <i>\$ millions</i> )	199	195	4

<sup>(1)</sup> The reporting currency of UNS Energy is the US dollar.

### Electricity Sales & Gas Volumes

The decrease in electricity sales was primarily due to lower mining retail and short-term wholesale sales, both due to the impact of less favourable commodity prices compared to 2015. The majority of short-term wholesale sales is flowed through to customers and has no impact on earnings. Gas volumes were comparable with 2015.

### Revenue

The decrease in revenue was mainly due to the flow through to customers of lower purchased power and fuel supply costs, lower mining retail and short-term wholesale electricity sales, and approximately \$29 million (US\$22 million), or \$18 million (US\$13 million) after tax, in FERC ordered transmission refunds. The decrease was partially offset by approximately \$47 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, \$17 million (US\$13 million), or \$10 million (US\$8 million) after tax, in revenue related to the settlement of Springerville Unit 1, and an increase in lost fixed-cost recovery revenue.

### Earnings

The increase in earnings was primarily due to the settlement of Springerville Unit 1, lower deferred income tax expense, approximately \$6 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, and an increase in lost fixed-cost recovery revenue. The increase was partially offset by FERC ordered transmission refunds, higher operating expenses and depreciation and amortization.

## CENTRAL HUDSON

<b>Financial Highlights</b>			
Years Ended December 31	2016	2015	Variance
Average US:CAD Exchange Rate <sup>(1)</sup>	1.33	1.28	0.05
Electricity Sales ( <i>GWh</i> )	5,112	5,132	(20)
Gas Volumes ( <i>PJ</i> )	24	24	—
Revenue ( <i>\$ millions</i> )	849	880	(31)
Earnings ( <i>\$ millions</i> )	70	58	12

<sup>(1)</sup> The reporting currency of Central Hudson is the US dollar.

### Electricity Sales & Gas Volumes

The decrease in electricity sales was mainly due to lower average consumption as a result of changes in temperatures, partially offset by the timing of customer billings as a result of regulatory approval to increase billing frequency to monthly, effective July 1, 2016. Gas volumes were comparable with 2015.

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 decrease in revenue was mainly due to the recovery from customers of lower commodity costs, which were mainly due to overall lower wholesale prices, and the impact of energy-efficiency incentives earned during the first half of 2015 upon achieving energy saving targets established by the regulator. The decrease was partially offset by higher delivery revenue from increases in base electricity rates effective July 1, 2015 and July 1, 2016 and approximately \$20 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue.

### Earnings

The increase in earnings was primarily due to increases in delivery revenue, approximately \$5 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, and lower-than-expected operating expenses. The increase was partially offset by the impact of energy-efficiency incentives earned during the first half of 2015, as discussed above.

## REGULATED GAS & ELECTRIC UTILITIES - CANADIAN

Regulated Gas & Electric Utilities - Canadian earnings for 2016 were \$390 million (2015 - \$390 million), which represented approximately 51% of the Corporation's total regulated earnings (2015 - 58%). Total segment assets were approximately \$14.8 billion as at December 31, 2016 (December 31, 2015 - \$14.2 billion), which represented approximately 32% of the Corporation's total regulated assets as at December 31, 2016 (December 31, 2015 - 52%). The decrease in percentage of regulated earnings and assets as compared to 2015 were due to the acquisition of ITC.

## FORTISBC ENERGY

<b>Financial Highlights</b>			
Years Ended December 31	<b>2016</b>	2015	Variance
Gas Volumes ( <i>PJ</i> )	<b>197</b>	186	11
Revenue ( <i>\$ millions</i> )	<b>1,151</b>	1,295	(144)
Earnings ( <i>\$ millions</i> )	<b>151</b>	140	11

### Gas Volumes

The increase in gas volumes was primarily due to customer growth, higher average consumption by residential and commercial customers in 2016 due to colder temperatures, and higher volumes for transportation customers due to certain transportation customers switching to natural gas compared to alternative fuel sources.

### Revenue

The decrease in revenue was primarily due to a lower commodity cost of natural gas charged to customers, partially offset by an increase in customer delivery rates effective January 1, 2016 and higher gas volumes.

### Earnings

The increase in earnings was primarily due to higher AFUDC associated with the Tilbury liquefied natural gas ("LNG") facility expansion ("Tilbury LNG Facility Expansion"), and operating expense savings, net of the earnings sharing mechanism. Changes in consumption levels and the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral mechanisms.

## FORTISALBERTA

<b>Financial Highlights</b>			
Years Ended December 31	2016	2015	Variance
Energy Deliveries ( <i>GWh</i> )	16,788	17,132	(344)
Revenue ( <i>\$ millions</i> )	572	563	9
Earnings ( <i>\$ millions</i> )	121	138	(17)

### Energy Deliveries

The decrease in energy deliveries was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas, and lower average consumption by residential, commercial and irrigation customers, mainly due to changes in weather. The decrease was partially offset by higher energy deliveries to residential customers due to growth in the number of customers.

### Revenue

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

The increase in revenue was due to an increase in customer rates effective January 1, 2016 based on a combined inflation and productivity factor of 0.9%, growth in the number of customers and higher revenue related to flow-through costs to customers. The increase was partially offset by the impact of a \$9 million positive capital tracker revenue adjustment recognized in 2015 that related to 2013 and 2014, lower average consumption, and a \$3 million negative capital tracker revenue adjustment as a result of the outcome of the 2016 GCOC Proceeding in Alberta.

### Earnings

The decrease in earnings was mainly due to the \$9 million positive capital tracker revenue adjustment recognized in the first half of 2015, lower average energy consumption, and higher operating expenses. The decrease was partially offset by rate base growth, tempered by the impact of the 2016 GCOC Proceeding, and growth in the number of customers.

## FORTISBC ELECTRIC

<b>Financial Highlights</b>			
Years Ended December 31	2016	2015	Variance
Electricity Sales ( <i>GWh</i> )	3,119	3,116	3
Revenue ( <i>\$ millions</i> )	377	360	17
Earnings ( <i>\$ millions</i> )	54	50	4

### Electricity Sales

Electricity sales were comparable with 2015.

### Revenue

The increase in revenue was driven by increases in base electricity rates and surplus capacity sales. Higher contribution from non-regulated operating, maintenance and management services associated with the Waneta Expansion also favourably impacted revenue.

### Earnings

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

## EASTERN CANADIAN ELECTRIC UTILITIES

<b>Financial Highlights</b>			
Years Ended December 31	2016	2015	Variance
Electricity Sales ( <i>GWh</i> )	8,374	8,403	(29)
Revenue ( <i>\$ millions</i> )	1,063	1,033	30
Earnings ( <i>\$ millions</i> )	64	62	2

### Electricity Sales

The decrease in electricity sales was primarily due to lower average consumption by residential customers in all regions, mainly due to warmer temperatures. The decrease was partially offset by customer growth in Newfoundland.

### Revenue

The increase in revenue was mainly due to the flow through in customer electricity rates of higher energy supply costs at Newfoundland Power and FortisOntario, partially offset by lower electricity sales.

### Earnings

The increase in earnings was primarily due to rate base growth and lower-than-forecast expenses at Newfoundland Power, and lower business development costs at FortisOntario. The increase was partially offset by a decrease in Newfoundland Power's allowed ROE effective January 1, 2016 and lower electricity sales.

## REGULATED ELECTRIC UTILITIES - CARIBBEAN

Regulated Electric Utilities - Caribbean earnings for 2016 were \$46 million (2015 - \$34 million), which represented approximately 6% of the Corporation's total regulated earnings (2015 - 5%). Total segment assets were approximately \$1.3 billion as at December 31, 2016 (December 31, 2015 - \$1.3 billion), which represented approximately 3% of the Corporation's total regulated assets as at December 31, 2016 (December 31, 2015 - 4%).

<b>Financial Highlights</b>			
Years Ended December 31	2016	2015	Variance
Average US:CAD Exchange Rate <sup>(1)</sup>	1.33	1.28	0.05
Electricity Sales ( <i>GWh</i> )	837	802	35
Revenue ( <i>\$ millions</i> )	301	321	(20)
Earnings ( <i>\$ millions</i> )	46	34	12

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

### Electricity Sales

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

### Revenue

The decrease in revenue was mainly due to the flow through in customer electricity rates of lower fuel costs. The decrease was partially offset by electricity sales growth and approximately \$4 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue.

### Earnings

The increase in earnings was primarily due to equity income from Belize Electricity, favourable foreign exchange of approximately \$4 million associated with the translation of US dollar-denominated earnings, and electricity sales growth. The increase was partially offset by higher depreciation and amortization.

## NON-REGULATED

### NON-REGULATED - ENERGY INFRASTRUCTURE

<b>Financial Highlights</b>			
Years Ended December 31	2016	2015	Variance
Energy Sales ( <i>GWh</i> )	901	844	57
Revenue ( <i>\$ millions</i> )	193	107	86
Earnings ( <i>\$ millions</i> )	60	77	(17)

#### Energy Sales

The increase in energy sales was driven by the Waneta Expansion, which commenced production in April 2015, and increased production in Belize. The increase was partially offset by lower energy sales due to the sale of generation assets in 2015 and February 2016.

#### Revenue

The increase in revenue was driven by the acquisition of Aitken Creek and a full year of contribution from the Waneta Expansion. The impacts of increased production in Belize and approximately \$1 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue were largely offset by lower revenue due to the sale of generation assets.

#### Earnings

The decrease in earnings was primarily due to the recognition of \$32 million in after-tax gains in 2015 on the sale of generation assets, and lower earnings due to the sale of generation assets. The decrease was partially offset by contribution of \$9 million from Aitken Creek, net of an after-tax \$6 million unrealized loss on the mark-to-market of derivatives, a full year of contribution from the Waneta Expansion, increased production in Belize, and approximately \$1 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings.

## NON-REGULATED – NON-UTILITY

<b>Financial Highlights</b>			
Years Ended December 31 ( <i>\$ millions</i> )	2016	2015	Variance
Revenue	—	171	(171)
Earnings	—	114	(114)

#### Revenue

The decrease in revenue was due to the sale of commercial real estate and hotel assets in 2015.

#### Earnings

The decrease in earnings was due to the sale of commercial real estate and hotels assets in 2015. In 2015, an after-tax net gain of approximately \$101 million was recognized related to the sale of commercial real estate and hotel assets.

## CORPORATE AND OTHER

<b>Financial Highlights</b>			
Years Ended December 31			
<i>(\$ millions)</i>	<b>2016</b>	2015	Variance
Revenue	<b>9</b>	24	(15)
Operating Expenses	<b>108</b>	36	72
Depreciation and Amortization	<b>4</b>	2	2
Other Income (Expenses), Net	<b>—</b>	2	(2)
Finance Charges	<b>162</b>	94	68
Income Tax Recovery	<b>(101)</b>	(43)	(58)
	<b>(164)</b>	(63)	(101)
Preference Share Dividends	<b>75</b>	77	(2)
<b>Net Corporate and Other Expenses</b>	<b>(239)</b>	(140)	(99)

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

- (i) Acquisition-related expenses totalling \$118 million (\$90 million after tax) in 2016 associated with ITC (2015 - \$10 million (\$7 million after tax)). Acquisition-related expenses included: (i) investment banking, legal, consulting and other fees totalling approximately \$79 million (\$62 million after tax) in 2016 (2015 - \$10 million (\$7 million after tax)), which were included in operating expenses; and (ii) fees associated with the Corporation's acquisition credit facilities and deal-contingent interest rate swap contracts totalling approximately \$39 million (\$28 million after tax) in 2016 (2015 - nil), which were included in finance charges;
- (ii) A foreign exchange gain of \$13 million in 2015 associated with the Corporation's previous US dollar-denominated long-term other asset that represented the book value of its expropriated investment in Belize Electricity, which was included in other income; and
- (iii) A loss of \$9 million in 2015 on settlement of expropriation matters related to the Corporation's investment in Belize Electricity, which was included in other income, net of expenses.

Excluding the above-noted items, net Corporate and Other expenses were \$149 million for 2016 compared to \$137 million for 2015. The increase was primarily due to higher finance charges, lower revenue, and higher operating expenses, partially offset by a higher income tax recovery.

The increase in finance charges was mainly due to the acquisition of ITC in October 2016. The impact of no longer capitalizing interest upon the completion of the Waneta Expansion in April 2015, finance charges associated with the acquisition of Aitken Creek in April 2016, and the impact of unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense also contributed to the increase in finance charges. The decrease in revenue was due to lower related-party interest income, mainly due to the sale of commercial real estate and hotel assets in 2015. The increase in operating expenses was primarily due to higher compensation-related expenditures, including higher stock-based compensation as a result of share price appreciation, business development costs, general inflationary increases and ancillary expenses to support the acquisition of ITC and the Corporation's listing on the New York Stock Exchange. The increase was partially offset by a \$3 million (\$2 million after tax) corporate donation recognized in 2015. The higher income tax recovery was mainly related to the increase in net Corporate and Other expenses and the Corporation's financing structure associated with the acquisition of ITC.

## REGULATORY HIGHLIGHTS

The following summarizes the significant regulatory decisions and applications for the Corporation's utilities for 2016.

### ITC

#### *ROE Complaints*

Since 2013 two third-party complaints were filed with FERC requesting that FERC find the MISO regional base ROE for all MISO transmission owners, including ITC Transmission, METC and ITC Midwest, for the periods November 2013 through February 2015 (the "Initial Refund Period") and February 2015 through May 2016 (the "Second Refund Period") to no longer be just and reasonable. In September 2016 FERC issued an order affirming the presiding ALJ's initial decision for the Initial Refund Period and setting the base ROE for the Initial Refund Period at 10.32%, with a maximum ROE of 11.35%. Additionally, the rates established by the September 2016 order will be used prospectively from the date of the order until a new approved rate is established for the Second Refund Period. In June 2016 the presiding ALJ issued an initial decision for the Second Refund Period, which recommended a base ROE of 9.70%, with a maximum ROE of 10.68%, which is a recommendation to FERC. A decision from FERC for the Second Refund Period is expected in 2017. The base ROE for the three affected utilities for the period of May 2016 through September 2016 was 12.38% and any authorized adders that were approved prior to the filing of the complaints were collected during this time, up to a maximum of 13.88%. As at December 31, 2016, the estimated range of refunds for both periods was between US\$221 million and US\$258 million and ITC has recognized an aggregate estimated regulatory liability of US\$258 million. In February 2017 ITC provided refunds totalling US\$119 million, including interest, for the initial complaint. The estimated regulatory liability was accrued by ITC before its acquisition by Fortis. It is possible that the outcome of these matters could differ materially from the estimated range of refunds.

#### *Challenges on Bonus Depreciation*

In December 2015 a formal challenge was filed with FERC alleging that ITC Midwest unreasonably and imprudently opted out of using bonus depreciation in the calculation of its federal income tax expense, resulting in increased charges for transmission service to customers. In March 2016 FERC issued an order requiring ITC Midwest to recalculate its revenue requirements, effective January 1, 2015, to simulate the election of bonus depreciation for 2015. While FERC denied the challenge for ITC Midwest to elect bonus depreciation in any past or future years, stakeholders are able to challenge any decision by ITC Midwest, or any of ITC's regulated operating subsidiaries, not to take bonus depreciation in future years. ITC's financial statements reflect the election of bonus depreciation for tax years 2015 and 2016, the corresponding effects on 2015 and 2016 revenue requirements for its regulated operating subsidiaries, and the corresponding refund obligation. The total impact from reflecting the election of bonus depreciation, as described above, was lower revenue of US\$20 million and lower net earnings of approximately US\$12 million for the year ended December 31, 2016, and an increase in deferred income tax liabilities of US\$109 million and a corresponding tax receivable of US\$12 million as at December 31, 2016. In addition, the above-noted elections resulted in an income tax refund of US\$128 million, which was received in August 2016. The election of bonus depreciation will result in higher cash flows in the year of election or future subsequent periods and a reduction in rate base, resulting in a decrease in revenue and net earnings over the tax lives of the eligible assets.

### UNS Energy

#### *General Rate Application*

In February 2017 the ACC issued a Rate Order on TEP's GRA filed in November 2015, based on a historical test year ended June 30, 2015. The 2017 Rate Order approved new rates effective on or before March 1, 2017. The provisions of the 2017 Rate Order include, but are not limited to: (i) an increase in non-fuel base revenue of US\$81.5 million, including US\$15 million of operating costs related to the 50.5% undivided interest in Springerville Unit 1 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 San Juan Unit 1. Certain aspects of the GRA, including net metering and rate design for distributed generation customers, have been deferred to a second rate case proceeding, which is expected to begin in the first half of 2017.

### *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 two 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 (US\$22 million), or \$18 million (US\$13 million) after tax, of which US\$17 million has been paid.

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 US\$8 million and TEP dismissed its appeal with prejudice. The impact of the settlement agreement will be recognized in the first quarter of 2017. FERC's Office of Enforcement is still reviewing the matter, and FERC could impose civil penalties on TEP as a result of this review. At this time, TEP cannot predict the outcome or the range of additional losses, if any.

## **FortisBC Energy and FortisBC Electric**

### *Generic Cost of Capital Proceeding*

In October 2015, as required by the regulator, FEI filed its application to review the 2016 benchmark allowed ROE and common equity component of capital structure. In August 2016 the British Columbia Utilities Commission ("BCUC") issued its decision on FEI's application, which reaffirmed FEI as the benchmark utility and established that the ROE and common equity component of capital structure for the benchmark utility would remain unchanged at 8.75% and 38.5%, respectively, both effective January 1, 2016. As FEI is the benchmark utility, FortisBC Electric's allowed ROE also remains unchanged at 9.15%.

## **FortisAlberta**

### *Capital Tracker Applications*

In February 2016 the Alberta Utilities Commission ("AUC") issued its decision related to FortisAlberta's 2014 True-Up and 2016-2017 Capital Tracker Applications, resulting in a capital tracker revenue adjustment of less than \$1 million. In January 2017 the AUC issued its decision on FortisAlberta's 2015 True-Up Application approving capital tracker revenue as filed, pending the Company's submission of a Compliance Filing in February 2017.

In September 2016 the AUC approved FortisAlberta's Compliance Filing related to the February 2016 capital tracker decision, including approval of capital tracker revenue of \$71 million and \$90 million for 2016 and 2017, respectively. The adjustments to capital tracker revenue have been included in FortisAlberta's 2017 Annual Rates Application. Any further differences between 2015 and 2016 capital tracker revenue collected from customers and actual capital expenditures will be included in 2017 applications to be refunded to or collected from customers in 2018.

FortisAlberta recognized capital tracker revenue of \$59 million for 2016, down \$12 million from the \$71 million approved in the Compliance Filing, which reflects actual capital expenditures and associated financing costs compared to forecast, and the impact of the 2016 GCOC Decision, as discussed below.

### *Generic Cost of Capital Proceeding*

In October 2016 the AUC issued its decision related to FortisAlberta's 2016 and 2017 GCOC Proceeding, establishing that FortisAlberta's allowed ROE remain unchanged at 8.30% for 2016 and increase to 8.50% for 2017. The decision also set the common equity component of capital structure at 37%, effective January 1, 2016, down from 40% approved on an interim basis. Changes in FortisAlberta's allowed ROE and common equity component of capital structure impact only the portion of rate base that is funded by capital tracker revenue.

### Next Generation PBR Proceeding

In December 2016 the AUC issued its decision outlining the manner in which distribution rates will be determined during the second PBR term, being the five-year period from 2018 through 2022. The parameters of the second PBR term are generally consistent with the first PBR term; except for: (i) the productivity factor, which is set at 0.3% for the second PBR term, as compared to 1.16% for the first PBR term; and (ii) the capital tracker mechanism, which will be replaced by two incremental capital funding mechanisms in the second PBR term. The capital funding mechanisms will include a capital tracker mechanism similar to the first PBR term for incremental capital not previously included in FortisAlberta's rate base, and a K-bar mechanism, submitted annually through the annual rates application, for all capital included in FortisAlberta's going-in rate base. The AUC has directed Alberta utilities to file a rebasing application in March 2017 to establish the going-in revenue requirement for the second PBR term, which will be used to determine the going-in rates upon which the PBR formula will be applied to establish distribution rates for 2018. A decision on this application is expected in the second half of 2017.

### Eastern Canadian Electric Utilities

In June 2016 the Newfoundland and Labrador Board of Commissioners of Public Utilities issued an order on Newfoundland Power's 2016/2017 GRA, with new customer rates effective July 1, 2016. The order, which established the cost of capital for rate-making purposes for 2016 through 2018, resulted in a decrease in the allowed ROE to 8.50% from 8.80%, effective January 1, 2016, on a 45% common equity component of capital structure. Newfoundland Power is required to file its next GRA for 2019 on or before June 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	Second MISO Base ROE Complaint	Not applicable	2017

## CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2016 and December 31, 2015. The increase due to ITC reflects the net assets acquired as at December 31, 2016.

### Significant Changes in the Consolidated Balance Sheets between December 31, 2016 and December 31, 2015

Balance Sheet Account	Increase Due to ITC (\$ millions)	Other Increase/Decrease (\$ millions)	Explanation for Other Increase/(Decrease)
Accounts receivable and other current assets	179	(16)	The decrease was not significant.
Regulatory assets - current and long-term	390	11	The increase was not significant.
Utility capital assets	8,608	1,134	The increase was mainly due to utility capital expenditures and the acquisition of Aitken Creek, partially offset by depreciation and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets.
Intangible assets	442	28	The increase was not significant.
Goodwill	8,246	(55)	The decrease was not significant.
Short-term borrowings	195	449	The increase was mainly due to drawings under the Corporation's equity bridge credit facility to finance a portion of the acquisition of ITC, partially offset by the repayment of short-term borrowings at FortisBC Energy using net proceeds from the issuance of long-term debt.

### Significant Changes in the Consolidated Balance Sheets between December 31, 2016 and December 31, 2015

Balance Sheet Account	Increase Due to ITC (\$ millions)	Other Increase/Decrease (\$ millions)	Explanation for Other Increase/(Decrease)
Accounts payable and other current liabilities	364	187	The increase was mainly due to higher customer deposits at FortisBC Energy and higher dividends payable at the Corporation, driven by an increase in the number of common shares outstanding. Higher amounts owing for energy supply costs and an increase in capital accruals at FortisBC Energy also contributed to the increase.
Other liabilities	165	(38)	The decrease was not significant.
Regulatory liabilities - current and long-term	496	49	The increase was not significant.
Long-term debt (including current portion)	6,461	3,439	The increase was mainly due to the issuance of long-term debt at the Corporation to finance a portion of the acquisition of ITC, the acquisition of Aitken Creek, and the redemption of First Preference Shares, Series E. Issuances of long-term debt at the regulated utilities, largely in support of energy infrastructure investment, were partially offset by regularly scheduled debt repayments and the impact of foreign exchange on the translation of US dollar-denominated debt.
Deferred income tax liabilities	991	222	The increase was mainly due to timing differences related to capital expenditures at the regulated utilities and the acquisition of Aitken Creek, partially offset by taxable losses at the Corporation and the impact of foreign exchange on the translation of US dollar-denominated deferred income tax liabilities.
Shareholders' equity (before non-controlling interests)	—	4,717	The increase was driven by the issuance of approximately 114.4 million common shares to finance a portion of the acquisition of ITC. Net earnings attributable to common equity shareholders for 2016, less dividends declared on common shares, and the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans also contributed to the increase. The increase was partially offset by the redemption of First Preference Shares, Series E.
Non-controlling interests	—	1,380	The increase was primarily due to proceeds from GIC's minority investment in ITC.

## LIQUIDITY AND CAPITAL RESOURCES

### SUMMARY OF CONSOLIDATED CASH FLOWS

The table below outlines the Corporation's sources and uses of cash in 2016 compared to 2015, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows			
Years ended December 31 (\$ millions)	2016	2015	Variance
<b>Cash, Beginning of Year</b>	<b>242</b>	230	12
<b>Cash Provided by (Used in):</b>			
Operating Activities	1,884	1,673	211
Investing Activities	(6,891)	(1,368)	(5,523)
Financing Activities	5,050	(346)	5,396
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(16)	53	(69)
<b>Cash, End of Year</b>	<b>269</b>	242	27

**Operating Activities:** Cash flow from operating activities in 2016 was \$211 million higher than in 2015. The increase was primarily due to higher cash earnings at the regulated utilities, driven by the acquisition of ITC, partially offset by the Corporation's acquisition-related expenses. Favourable changes in long-term regulatory deferrals were partially offset by unfavourable changes in working capital.

**Investing Activities:** Cash used in investing activities in 2016 was \$5,523 million higher than in 2015. The increase was driven by the acquisition of ITC in October 2016 for net cash consideration of approximately \$4.5 billion (US\$3.5 billion) and the acquisition of Aitken Creek in April 2016 for a net purchase price of \$318 million. Proceeds received from the sale of commercial real estate, hotel and generation assets in 2015 of approximately \$430 million, \$365 million and \$77 million (US\$63 million), respectively, also contributed to the increase in cash used in investing activities.

Capital expenditures for 2016 were \$182 million lower than 2015 mainly due to lower capital spending at UNS Energy, FortisBC Energy and FortisAlberta. The decrease in capital spending at UNS Energy was mainly due to the purchase of additional ownership interests in the Springerville Unit 1 generating facility and previously leased coal-handling assets in 2015, partially offset by the purchase of the third-party owners' 50.5% undivided interest in Springerville Unit 1 generating facility for US\$85 million in 2016. Lower capital spending at FortisBC Energy was related to the Tilbury LNG Facility Expansion and the decrease at FortisAlberta was mainly due to lower Alberta Electric System Operator ("AESO") contributions and lower capital expenditures for new customers. The decrease in capital expenditures was partially offset by investments of approximately US\$167 million at ITC from the date of acquisition.

**Financing Activities:** Cash provided by financing activities in 2016 was \$5,396 million higher than in 2015. The increase was driven by financing activities associated with the acquisition of ITC. The net cash consideration associated with the acquisition of ITC was financed using: (i) net proceeds from the issuance of US\$2.0 billion unsecured notes in October 2016; (ii) net proceeds from GIC's US\$1.228 billion minority investment, which includes a shareholder note of US\$199 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 addition to the impact of financing activities associated with ITC, higher net borrowings under committed credit facilities, lower repayments of long-term debt and higher proceeds from the issuance of long-term debt also contributed to the increase in cash provided by financing activities. The increase was partially offset by other changes in short-term borrowings and the redemption of preference shares.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease and finance obligations, and net borrowings (repayments) under committed credit facilities for 2016 and 2015 are summarized in the following tables.

<b>Proceeds from Long-Term Debt, Net of Issue Costs</b>			
Years ended December 31			
(\$ millions)	2016	2015	Variance
ITC <sup>(1)</sup>	264	—	264
UNS Energy <sup>(2)</sup>	—	591	(591)
Central Hudson <sup>(3)</sup>	68	25	43
FortisBC Energy <sup>(4)</sup>	446	150	296
FortisAlberta <sup>(5)</sup>	149	149	—
Eastern Canadian <sup>(6)</sup>	40	75	(35)
Caribbean Electric <sup>(7)</sup>	65	12	53
Corporate <sup>(8)</sup>	3,104	—	3,104
<b>Total</b>	<b>4,136</b>	<b>1,002</b>	<b>3,134</b>

<sup>(1)</sup> 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.

<sup>(2)</sup> In February 2015 TEP issued 10-year US\$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures. In April 2015 UNS Electric issued 30-year US\$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes. In August 2015 UNS Electric issued 12-year US\$80 million 3.22% unsecured notes and UNS Gas issued 30-year US\$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt.

- (3) 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. In March 2015 Central Hudson issued 10-year US\$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.
- (4) 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. In April 2015 FortisBC Energy issued 30-year \$150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings.
- (5) 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. In September 2015 FortisAlberta issued 30-year \$150 million 4.27% senior unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.
- (6) 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. In September 2015 Newfoundland Power issued 30-year \$75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.
- (7) In 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. In January 2015 Fortis Turks and Caicos issued 15-year US\$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.
- (8) 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.

<b>Repayments of Long-Term Debt and Capital Lease and Finance Obligations</b>			
Years ended December 31			
(\$ millions)	2016	2015	Variance
UNS Energy	(19)	(449)	430
Central Hudson	(11)	—	(11)
FortisBC Energy	(212)	(92)	(120)
FortisBC Electric	(25)	—	(25)
Eastern Canadian	(48)	(6)	(42)
Caribbean Electric	(21)	(21)	—
Other	—	(34)	34
<b>Total</b>	<b>(336)</b>	<b>(602)</b>	<b>266</b>

<b>Net Borrowings (Repayments) Under Committed Credit Facilities</b>			
Years ended December 31			
(\$ millions)	2016	2015	Variance
ITC	111	—	111
UNS Energy	33	(199)	232
FortisAlberta	(53)	30	(83)
Eastern Canadian	43	(47)	90
Corporate <sup>(1)</sup>	(41)	(406)	365
<b>Total</b>	<b>93</b>	<b>(622)</b>	<b>715</b>

- (1) Repayments under the Corporation's committed credit facility in 2015 were made using net proceeds from the sale of commercial real estate and hotel assets in 2015, partially offset by borrowings to finance equity injections into UNS Energy and FortisBC Energy, and for other 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.

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

Common share dividends paid in 2016 totalled \$316 million, net of \$162 million of dividends reinvested, compared to \$232 million, net of \$156 million of dividends reinvested, paid in 2015. 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 \$1.53 in 2016 compared to \$1.40 in 2015. The weighted average number of common shares outstanding was 308.9 million for 2016 compared to 278.6 million for 2015.

## 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, 2016, are outlined in the following table.

Contractual Obligations As at December 31, 2016 (\$ millions)	Total	Due	Due in	Due in	Due in	Due in	Due
		within 1 year	year 2	year 3	year 4	year 5	after 5 years
Long-term debt	21,219	251	931	679	725	1,756	16,877
Interest obligations on long-term debt	14,586	892	854	837	817	793	10,393
Capital lease and finance obligations <sup>(1)</sup>	2,422	121	92	76	73	81	1,979
Power purchase obligations <sup>(2)</sup>	2,295	290	200	119	107	107	1,472
Renewable power purchase obligations <sup>(3)</sup>	1,625	100	99	99	98	97	1,132
Gas purchase obligations <sup>(4)</sup>	1,329	411	290	177	141	110	200
Long-term contracts - UNS Energy <sup>(5)</sup>	1,146	192	161	161	127	85	420
ITC easement agreement <sup>(6)</sup>	453	13	13	13	13	13	388
Operating lease obligations	175	13	13	11	8	7	123
Renewable energy credit purchase agreements <sup>(7)</sup>	154	20	15	12	12	12	83
Purchase of Springerville Common Facilities <sup>(8)</sup>	91	—	—	—	—	91	—
Waneta Partnership promissory note	72	—	—	—	72	—	—
Joint-use asset and shared service agreements	53	3	3	3	3	3	38
Other <sup>(9)</sup>	156	93	18	19	—	—	26
<b>Total</b>	<b>45,776</b>	<b>2,399</b>	<b>2,689</b>	<b>2,206</b>	<b>2,196</b>	<b>3,155</b>	<b>33,131</b>

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

<sup>(2)</sup> 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 \$743 million as at December 31, 2016, 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 \$486 million as at December 31, 2016.

*FortisBC Electric:* Power purchase obligations for FortisBC Electric, totalling \$288 million as at December 31, 2016, 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 for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Contractual Obligations table as they 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, 2016, had commitments of \$480 million under this arrangement.

- (3) TEP and UNS Electric are party to long-term renewable PPAs totalling approximately US\$1,210 million as at December 31, 2016, which require TEP and UNS Electric 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 2030 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, 2016.
- (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, with obligations totalling US\$496 million, US\$244 million and US\$113 million, respectively, as at December 31, 2016. 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. UNS Energy’s renewable energy credit purchase agreements totalled approximately US\$107 million as at December 31, 2016 for the purchase of environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.
- (8) UNS Energy has an obligation to purchase an undivided 32.2% leased interest in the Springerville Common Facilities if the related two leases are not renewed, for a total purchase price of US\$68 million.
- (9) 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, 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 \$3.0 billion for 2017. Over the five years 2017 through 2021, the Corporation’s consolidated capital expenditure program is expected to be approximately \$13 billion, which has not been included in the Contractual Obligations table.

*Other:* CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling US\$1.7 billion, of which CH Energy Group's maximum commitment is US\$182 million. CH Energy Group issued a parental guarantee to assure the payment of the maximum commitment of US\$182 million. As at December 31, 2016, there was no obligation under this guarantee.

In 2016 FHI issued a parental guarantee of \$77 million to secure the storage optimization transactions of Aitken Creek.

The Corporation's long-term regulatory liabilities of \$2,183 million as at December 31, 2016 have been excluded from the Contractual Obligations table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known.

## CAPITAL STRUCTURE

The Corporation's principal businesses of regulated electric and gas utilities require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings, and advances from minority investors. 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	2016		2015	
	(\$ millions)	(%)	(\$ millions)	(%)
Total debt and capital lease and finance obligations (net of cash) <sup>(1)</sup>	22,490	60.6	11,950	54.8
Preference shares	1,623	4.4	1,820	8.3
Common shareholders' equity	12,974	35.0	8,060	36.9
<b>Total</b>	<b>37,087</b>	<b>100.0</b>	21,830	100.0

<sup>(1)</sup> 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, 2016 was 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 (December 31, 2015 - 53.6% total debt and capital lease and finance obligations (net of cash), 8.2% preference shares, 36.1% common shareholders' equity and 2.1% non-controlling interests).

The acquisition of ITC significantly impacted the components of the Corporation's consolidated capital structure and included the following: (i) the issuance of US\$2.0 billion unsecured notes and borrowings under the Corporation's non-revolving term senior unsecured equity bridge credit facility to finance a portion of the acquisition; (ii) debt assumed upon acquisition; (iii) the issuance of 114.4 million common shares, representing share consideration for the acquisition; and (iv) proceeds from GIC's US\$1.228 billion minority investment, which includes a shareholder note of US\$199 million. The Corporation expects to repay borrowings under the equity bridge facility using proceeds from a common equity offering in 2017.

The capital structure was also impacted by: (i) the issuance of long-term debt at the Corporation, primarily to finance the acquisition of Aitken Creek and the redemption of First Preference Shares, Series E, and at the regulated utilities, largely in support of energy infrastructure investment, partially offset by regularly scheduled debt repayments and the impact of foreign exchange on the translation of US-dollar denominated debt; (ii) net earnings attributable to common equity shareholders for 2016, less dividends declared on common shares; (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans; and (iv) the redemption of First Preference Shares, Series E.

## CREDIT RATINGS

As at December 31, 2016, 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	Stable
DBRS	BBB (high)	Unsecured debt	Stable
Moody's Investor Service ("Moody's")	Baa3	Issuer	Stable
	Baa3	Unsecured debt	Stable

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 September 2016 Moody's commenced rating Fortis. In October 2016, following the completion of the acquisition of ITC, DBRS revised the Corporation's unsecured debt credit rating to BBB (high) from A (low) and revised its outlook to stable from under review with negative implications, and S&P affirmed the Corporation's long-term corporate and unsecured debt credit ratings as A- and BBB+, respectively, and revised its outlook to stable from negative.

## 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 \$330 million in maintenance and repairs was expensed in 2016 compared to approximately \$302 million in 2015. The increase was largely due to the acquisition of ITC in 2016.

Gross consolidated capital expenditures for 2016 were approximately \$2.1 billion. A breakdown of these capital expenditures by segment and asset category for 2016 is provided in the following table.

Gross Consolidated Capital Expenditures <sup>(1)</sup>											
Year Ended December 31, 2016											
(\$ millions)											
	Regulated Utilities								Total Regulated Utilities	Non-Regulated <sup>(2)</sup>	Total
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric			
Generation	—	257	—	—	—	3	23	50	333	19	352
Transmission	195	33	38	72	—	11	16	2	367	—	367
Distribution	—	150	144	133	285	38	103	27	880	—	880
Facilities, equipment, vehicles and other <sup>(3)</sup>	14	38	26	113	68	16	8	22	305	10	315
Information technology	14	46	25	18	22	6	11	5	147	—	147
<b>Total</b>	<b>223</b>	<b>524</b>	<b>233</b>	<b>336</b>	<b>375</b>	<b>74</b>	<b>161</b>	<b>106</b>	<b>2,032</b>	<b>29</b>	<b>2,061</b>

<sup>(1)</sup> Represents cash payments to construct utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC.

<sup>(2)</sup> Includes Energy Infrastructure and Corporate and Other segments

<sup>(3)</sup> 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. Gross consolidated capital expenditures of \$2.1 billion for 2016 were \$160 million higher than \$1.9 billion forecast for 2016, as disclosed in the MD&A for the year ended December 31, 2015. The increase was primarily due to capital investments at ITC of US\$167 million from the date of acquisition. Capital spending at UNS Energy was

higher than forecast primarily due to the purchase of the remaining 50.5% undivided interest in Springerville Unit 1 for US\$85 million in September 2016, which was partially offset by lower capital expenditures for system reinforcement and renewables. The higher-than-forecast capital expenditures for 2016 was partially offset by lower capital spending at FortisAlberta, primarily due to lower AESO contributions and as a result of the current economic downturn in Alberta, and the impact of foreign exchange associated with the translation of US dollar-denominated capital expenditures.

Gross consolidated capital expenditures for 2017 are expected to be approximately \$3.0 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2017 is provided in the following table.

<b>Forecast Gross Consolidated Capital Expenditures <sup>(1)</sup></b>											
<b>Year Ending December 31, 2017</b>											
<i>(\$ millions)</i>											
	<b>Regulated Utilities</b>								<b>Total Regulated Utilities</b>	<b>Non-Regulated <sup>(2)</sup></b>	<b>Total</b>
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric			
Generation	—	161	3	—	—	19	6	45	<b>234</b>	<b>7</b>	<b>241</b>
Transmission	907	84	30	215	—	20	18	17	<b>1,291</b>	<b>—</b>	<b>1,291</b>
Distribution	—	185	142	131	303	41	113	23	<b>938</b>	<b>—</b>	<b>938</b>
Facilities, equipment, vehicles and other <sup>(3)</sup>	24	54	29	99	95	24	8	10	<b>343</b>	<b>11</b>	<b>354</b>
Information technology	27	36	18	22	21	7	8	4	<b>143</b>	<b>—</b>	<b>143</b>
<b>Total</b>	<b>958</b>	<b>520</b>	<b>222</b>	<b>467</b>	<b>419</b>	<b>111</b>	<b>153</b>	<b>99</b>	<b>2,949</b>	<b>18</b>	<b>2,967</b>

<sup>(1)</sup> Represents forecast cash payments to construct utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC. Forecast capital expenditures for 2017 are based on a forecast exchange rate of US\$1.00=CAD\$1.30. Based on the closing foreign exchange rate on December 31, 2016 of US\$1.00=CAD\$1.34 forecast capital expenditures for 2017 would be approximately \$3.0 billion.

<sup>(2)</sup> Includes Energy Infrastructure and Corporate and Other segments

<sup>(3)</sup> 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 2016 actual and 2017 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows.

<b>Gross Consolidated Capital Expenditures</b>		
Year Ending December 31	<b>Actual</b>	Forecast
<i>(%)</i>	<b>2016</b>	2017
Growth <sup>(1)</sup>	<b>29</b>	39
Sustaining <sup>(2)</sup>	<b>54</b>	48
Other <sup>(3)</sup>	<b>17</b>	13
<b>Total</b>	<b>100</b>	100

<sup>(1)</sup> Includes capital expenditures associated with the Tilbury LNG Facility Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

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

<sup>(3)</sup> Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period 2017 through 2021, gross consolidated capital expenditures are expected to be approximately \$13 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 57% at U.S. Regulated Electric & Gas Utilities, including 28% at ITC; 39% at Canadian Regulated Gas & Electric Utilities; 3% at Caribbean Regulated Electric Utilities; and the remaining 1% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 58% for sustaining capital expenditures, 30% to meet customer growth, and 12% for facilities, equipment, vehicles, information technology and other assets.

Actual 2016 and forecast 2017 midyear rate base for the Corporation's regulated utilities and the Waneta Expansion is provided in the following table.

<b>Midyear Rate Base</b> (\$ billions)	<b>Actual</b> <b>2016</b>	Forecast 2017
ITC <sup>(1)</sup>	<b>6.9</b>	7.3
UNS Energy <sup>(1)</sup>	<b>4.6</b>	4.7
Central Hudson <sup>(1)</sup>	<b>1.5</b>	1.6
FortisBC Energy <sup>(2)</sup>	<b>3.7</b>	4.1
FortisAlberta	<b>2.9</b>	3.2
FortisBC Electric	<b>1.3</b>	1.3
Eastern Canadian	<b>1.7</b>	1.7
Caribbean Electric <sup>(1)</sup>	<b>0.9</b>	1.0
Waneta Expansion	<b>0.8</b>	0.8
<b>Total</b>	<b>24.3</b>	25.7

<sup>(1)</sup> Actual midyear rate base for 2016 is based on the actual average exchange rate of US\$1.00=CAD\$1.33 and forecast midyear rate base for 2017 is based on a forecast exchange rate of US\$1.00=CAD\$1.30. Based on the closing foreign exchange rate on December 31, 2016 of US\$1.00=CAD\$1.34 forecast midyear rate base for 2017 would be approximately \$26.1 billion.

<sup>(2)</sup> Forecast midyear rate base for 2017 includes approximately \$0.4 billion related to the Tilbury LNG Facility Expansion, prior to the inclusion of AFUDC and development costs, which is subject to a regulatory return.

The most significant capital projects that are included in the Corporation's base consolidated capital expenditures for 2016 and 2017 are summarized in the table below.

<b>Significant Capital Projects</b> <sup>(1)</sup>				Forecast	Expected	
(\$ millions)		Pre-	<b>Actual</b>	Forecast	Year of	
<b>Company</b>	<b>Nature of Project</b>	2016	<b>2016</b>	2017	2018-2021	Completion
ITC <sup>(2)(3)</sup>	Multi-Value Regional Transmission Projects ("MVPs")	—	<b>57</b>	354	96	Post-2021
	34.5 to 69 kilovolt ("kV") Conversion Project	—	<b>11</b>	89	369	Post-2021
UNS Energy <sup>(3)</sup>	Springerville Unit 1 Purchase	—	<b>112</b>	—	—	2016
Central Hudson <sup>(3)</sup>	Gas Main Replacement Program	26	<b>26</b>	33	169	Post-2021
FortisBC Energy	Tilbury LNG Facility Expansion <sup>(4)</sup>	326	<b>79</b>	65	—	2017
	Lower Mainland System Upgrade	15	<b>28</b>	162	220	2018
FortisAlberta	Pole-Management Program	200	<b>45</b>	43	53	Post-2021
Caribbean Utilities	Generation Expansion	73	<b>26</b>	—	—	2016

<sup>(1)</sup> Represents utility capital asset and intangible asset expenditures, including both the capitalized debt and equity components of AFUDC, where applicable

<sup>(2)</sup> Capital expenditures for 2016 are from the date of the acquisition.

<sup>(3)</sup> Forecast capital expenditures are based on a forecast exchange rate of US\$1.00=CAD\$1.30 for 2017 through 2021.

<sup>(4)</sup> Total project investment as at December 31, 2015 and 2016 includes approximately \$11 million and \$7 million, respectively, in non-cash capital accruals.

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. The MVPs are in various stages of construction and include construction of new breaker stations, new transmission lines and the extension of existing substations. Approximately US\$43 million was invested in the MVPs from the date of acquisition and an additional US\$272 million is expected to be spent in 2017. Three of the MVPs are expected to be completed by the end of 2018, with the fourth scheduled for completion in 2023.

The 34.5 to 69 kV Conversion Project at ITC consists of multiple capital initiatives designed to construct and rebuild new 69-kV lines, with in-service dates ranging from 2017 to post 2021. Approximately US\$352 million is expected to be invested in this project over the five-year period through 2021.

In September 2016 UNS Energy purchased the remaining 50.5% undivided interest in Springerville Unit 1 as part of a settlement agreement with the third-party owners for US\$85 million.

The Gas Main Replacement Program at Central Hudson is a 15-year replacement program to eliminate and replace leakage-prone pipes throughout the gas distribution system. The proposed replacement program increases the rate of annual expenditures on pipe replacements to approximately US\$30 million to expedite the replacement plan. Approximately US\$20 million was spent on this program in 2016 and an additional US\$25 million is expected to be spent in 2017. The majority of spending is expected post 2021.

FortisBC Energy's ongoing Tilbury LNG Facility Expansion is estimated at a total project cost of approximately \$470 million, including approximately \$70 million of AFUDC and development costs, which could be impacted by the date the project is put in use for rate-making purposes. The facility will include a second LNG tank and a new liquefier, both to be in service in mid-2017. FortisBC Energy received an Order in Council from the Government of British Columbia exempting the Tilbury LNG Facility Expansion from further regulatory review. Key construction activities in 2016 were focused on construction of the LNG storage tank and control building and the installation of the liquefaction process area major equipment. The commissioning and start-up phase of the project also commenced in the fourth quarter of 2016. Total project costs to the end of 2016 were approximately \$405 million, including AFUDC and development costs, and \$65 million is expected to be incurred on completion of the project in 2017.

The Lower Mainland System Upgrade project at FortisBC Energy is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia. The project will be completed in two phases: (i) the Lower Mainland Intermediate Pressure System Upgrade project phase, which is focused on addressing pipeline condition issues, estimated at \$255 million; and (ii) the Coastal Transmission System phase, which is intended to increase security of supply, estimated at \$170 million. The project has an estimated total capital cost of \$425 million, with approximately \$162 million forecast to be spent in 2017, and is expected to be completed in 2018. The BCUC approved the application to replace certain sections of intermediate pressure pipeline segments within the Greater Vancouver area in October 2015. The Coastal Transmission System phase was approved by a Special Direction by the Government of British Columbia in 2014 and will not be subject to further regulatory review.

During 2016 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program to extend the service life of existing poles and to replace poles when deterioration is beyond repair. The total capital cost of the program through 2021 is expected to be approximately \$341 million. Approximately \$45 million was spent on this program in 2016, for a total of \$245 million spent to the end of 2016.

In the second quarter of 2016, Caribbean Utilities completed its 39.7-MW generation expansion project, which included two 18.5 MW diesel-generating units, one 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment. The generating units replaced retiring generators and provide firm capacity to meet expected load growth. The generation expansion project was completed on schedule and below budget, for a total cost of US\$79 million.

## **ADDITIONAL INVESTMENT OPPORTUNITIES**

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

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

FortisBC Energy's potential pipeline expansion is conditional on Woodfibre LNG proceeding with its LNG export facility. Woodfibre LNG has obtained an export license from the National Energy Board 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. The potential pipeline expansion had an estimated total project cost of up to \$600 million, however, this estimate will be updated for final scoping, detailed construction estimates and scheduling. In November 2016 Woodfibre LNG 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 complete the project. This project could move forward in 2017 pending additional approvals and a final investment decision by Woodfibre LNG.

The Corporation's Tilbury LNG Facility 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. The further expansion of Tilbury is conditional upon having long-term supply contracts in place with investment-grade off-takers. In July 2016, following the dissolution of a proposed merger between Hawaiian Electric Company, Inc. ("Hawaiian Electric") and NextEra Energy Resources, the 20-year agreement between Fortis Hawaii Energy Inc., a wholly owned subsidiary of Fortis, and Hawaiian Electric to export LNG to Hawaii was terminated. Despite the termination of the agreement with Hawaiian Electric, Fortis continues to have discussions with a number of other potential export customers.

The Lake Erie Connector project at ITC 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 ("PJM"). 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 ("DOE") for the Lake Erie Connector transmission line, which is a required approval for international border-crossing projects. Also in January, ITC received a report from Canada's National Energy Board recommending the issuance of a Certificate of Public Convenience and Necessity with prescribed conditions for the transmission line. The project continues to advance through regulatory, operational, and economic milestones. Key milestones for 2017 include: receiving approval from the U.S. Army Corps of Engineers and Pennsylvania Department of Environmental Protection in a joint application; completing project cost refinements; and securing favourable transmission service agreements with prospective counterparties. Pending achievement of key milestones, the expected in-service date for the project is late 2020.

The Wataynikaneyap Power Project continues to advance in Ontario. Wataynikaneyap Power consists of a partnership between 22 First Nations and FortisOntario, with a mandate to develop new transmission lines to connect remote First Nations communities to clean electricity in Ontario. In the second quarter of 2016, the Government of Ontario designated Wataynikaneyap Power as the licensed transmission company to complete this project and an application for a deferral account was filed with the Ontario Energy Board ("OEB") in August 2016. In December 2016 FortisOntario reached an agreement with Renewable Energy Systems Canada to acquire its ownership interest in the Wataynikaneyap Partnership. The transaction is subject to approval by the OEB and is expected to close in the first quarter of 2017. As a result, FortisOntario's ownership interest in the Wataynikaneyap Partnership will increase to 49%, with the remaining 51% ownership interest held by the 22 First Nations communities. The total estimated capital cost for the project is approximately \$1.35 billion and is expected to contribute to savings of over \$1 billion for the First Nations communities and result in a significant reduction in greenhouse gas emissions. Regulatory approvals are currently being sought. In addition to environmental assessments which are underway, an order from the OEB establishing a deferral account to record costs is expected in 2017. The next regulatory milestone will be the preparation and filing of the leave to construct with the OEB.

The Corporation also has other significant opportunities that have not yet been included in the Corporation's capital expenditure forecast including, but not limited to: transmission investment opportunities at ITC; the New York Transco, LLC to address electric transmission constraints in New York State; renewable energy alternatives and transmission investments at UNS Energy; further gas infrastructure opportunities at FortisBC Energy; and potential further consolidation of Rural Electrification Associations at FortisAlberta.

## CASH FLOW REQUIREMENTS

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flows available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, 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 operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis. 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 operating subsidiaries to pay dividends based on management's intent to maintain the regulator-approved capital structures for each of its regulated operating subsidiaries. The Corporation does not expect that maintaining the targeted capital structures of its regulated operating 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 and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt, and advances from minority investors. 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 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 December 2016 Fortis issued \$500 million unsecured notes at 2.85% under the base shelf prospectus.

As at December 31, 2016, management expects consolidated fixed-term debt maturities and repayments to be \$190 million in 2017 and to average approximately \$680 million annually over the next five years. The combination of available credit facilities 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, 2016 and are expected to remain compliant in 2017.

## CREDIT FACILITIES

As at December 31, 2016, the Corporation and its subsidiaries had consolidated credit facilities of approximately \$6.0 billion, of which approximately \$3.7 billion was unused, including \$915 million 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 \$5.1 billion of the total credit facilities are committed facilities with maturities ranging from 2017 through 2021.

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

<b>Credit Facilities</b> (\$ millions)	Regulated Utilities	Corporate and Other	<b>Total as at December 31, 2016</b>	Total as at December 31, 2015
Total credit facilities <sup>(1)</sup>	3,823	2,153	<b>5,976</b>	3,565
Credit facilities utilized:				
Short-term borrowings <sup>(1)</sup>	(640)	(515)	<b>(1,155)</b>	(511)
Long-term debt (including current portion) <sup>(2)</sup>	(508)	(465)	<b>(973)</b>	(551)
Letters of credit outstanding	(68)	(51)	<b>(119)</b>	(104)
<b>Credit facilities unused <sup>(1)</sup></b>	<b>2,607</b>	<b>1,122</b>	<b>3,729</b>	<b>2,399</b>

<sup>(1)</sup> Total credit facilities and short-term borrowings as at December 31, 2016 include \$195 million (US\$145 million) outstanding under ITC's commercial paper program. Outstanding commercial paper does not reduce available capacity under the Corporation's consolidated credit facilities.

<sup>(2)</sup> As at December 31, 2016, credit facility borrowings classified as long-term debt included \$61 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2015 - \$71 million).

As at December 31, 2016 and 2015, 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\$1.0 billion in unsecured committed revolving credit facilities maturing in March 2019. ITC has an ongoing commercial paper program in an aggregate amount of US\$400 million, under which US\$145 million in commercial paper was outstanding as at December 31, 2016.

UNS Energy has a total of US\$350 million in unsecured committed revolving credit facilities, with US\$305 million maturing in October 2021, and US\$45 million maturing in October 2020.

Central Hudson has a US\$200 million unsecured committed revolving credit facility, maturing in October 2020, and an uncommitted credit facility totalling US\$25 million.

FortisBC Energy has a \$700 million unsecured committed revolving credit facility, maturing in August 2021.

FortisAlberta has a \$250 million unsecured committed revolving credit facility, maturing in August 2021, and a \$90 million bilateral credit facility, maturing in November 2017.

FortisBC Electric has a \$150 million unsecured committed revolving credit facility, maturing in May 2019, and a \$10 million unsecured demand overdraft facility.

Newfoundland Power has a \$100 million unsecured committed revolving credit facility, maturing in August 2021, and a \$20 million demand credit facility. Maritime Electric has a \$50 million unsecured committed revolving credit facility, maturing in February 2019. FortisOntario has a \$30 million unsecured committed revolving credit facility, maturing in June 2019.

Caribbean Utilities has unsecured credit facilities totalling approximately US\$49 million. Fortis Turks and Caicos has short-term unsecured demand credit facilities of US\$31 million, maturing in June 2017.

#### *Corporate and Other*

Fortis has a \$1.3 billion unsecured committed revolving credit facility, maturing in July 2021, and 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, maturing in October 2017.

UNS Energy Corporation has a US\$150 million unsecured committed revolving credit facility, with US\$130 million maturing in October 2021, and US\$20 million maturing in October 2020. CH Energy Group has a US\$50 million unsecured committed revolving credit facility, maturing in July 2020. FHI has a \$50 million unsecured committed revolving credit facility, maturing in April 2019.

## OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of \$119 million as at December 31, 2016 (December 31, 2015 - \$104 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 Corporations' 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 comprised approximately 97% of total assets of Fortis as at December 31, 2016 (December 31, 2015 – 96%). Approximately 97% of the Corporation's operating revenue<sup>1</sup> was derived from regulated utility operations in 2016 (2015 – 96%), and approximately 93% of the Corporation's operating earnings<sup>1</sup> were derived from regulated utility operations in 2016 (2015 – 92% excluding the gains on sale of non-core assets). 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 an approved revenue requirement.

For those utilities that follow COS regulation in determining annual revenue requirements and resulting customer rates, with the exception of ITC, 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.

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

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 Corporations' 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.

For additional information on various 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 rate templates 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 rate templates 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 any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then FERC will make appropriate prospective adjustments to them and/or disallow the inclusion of those aspects in the rate-setting formula. 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. Such rates affect allowed ROEs as the regulatory process may consider the general level of interest rates as a factor for setting allowed ROEs. The continuation of 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 begin to increase, regulatory lag may cause a delay in any resulting increase in the regulatory 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. A change in the level of interest rates could affect the measurement and disclosure of the fair value of long-term debt.

---

***If 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 Fortis.***

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 rate 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. 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. 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.

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 utilities' business, results of operations, financial condition and cash flows.***

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 any such changes in U.S. federal energy laws, regulations or policies in the future.

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

As a result of the Energy Policy Act of 2005, owners, operators and users of bulk electricity systems in the United States are subject to mandatory reliability standards developed by the North American Electric Reliability Corporation ("NERC") and its regional entities, which are approved and enforced by FERC. The standards are based on the functions that need to be performed to ensure that the bulk electricity system operates reliably. The Corporation's utilities located in the United States, British Columbia and Alberta have been, and will continue to be, subject to routine audits and monitoring with respect to compliance with applicable NERC reliability standards, including standards approved by FERC that will result in an increase in the number of assets (including cyber-security assets) designated as "critical assets". NERC and FERC can be expected to continue to refine existing reliability standards, as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject the Corporation's utilities located in the United States, British Columbia and Alberta to new requirements, potentially resulting in higher operating costs and/or increased capital expenditures. If any of the Corporation's utilities located in the United States were found not to be in compliance with the mandatory reliability standards, it could be subject to penalties of up to US\$1 million per day per violation. Both the costs of regulatory compliance and the costs that may be imposed as a result of any 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, that 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, where applicable, 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 Fortis and/or its subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt, the Corporation's financial condition 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 2017 are expected to total \$190 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 2016 there were no changes made to debt credit ratings of the Corporation's utilities, with the exception of S&P's downgrade of Central Hudson's senior unsecured debt rating to 'A-' from 'A' and revision of its outlook to stable from negative in June 2016. 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 schedule delays and project cost overruns. Capital expenditures at the utilities are generally approved by the respective regulators, 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.

Management believes that the acquisition of ITC will provide benefits to the Corporation, including an accretive effect on earnings per common share in the first full year following closing (excluding acquisition-related expenses). However, there is a risk that some or all of the expected benefits of the acquisition may fail to materialize, or may not occur within the time periods anticipated. The realization of such benefits may be impacted by a number of factors, including regulatory considerations and decisions, many of which are beyond the control of the Corporation. Realization of the anticipated benefits of the acquisition will depend, in part, on the Corporation's ability to successfully integrate ITC's business, including the requirement to devote management attention and resources to integrating business practices and support functions. The diversion of management's attention, any delays or difficulties encountered in connection with the integration, or the failure to realize all of the anticipated benefits of the acquisition could have an adverse effect on the Corporation's business, results of operations, financial condition or cash flows.

***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 Corporation's business operations 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. Software and information technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business and customer information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

In the event the Corporation's utilities' information 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 recovery.

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

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 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. Global warming and 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 it will receive fixed energy and capacity entitlements 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 result in significant losses.***

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, purchased power and coal. 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, power 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 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, 2016, the Corporation's corporately issued US\$3,511 million (December 31, 2015 – US\$1,535 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, 2016, the Corporation had approximately US\$7,250 million (December 31, 2015 – US\$3,137 million) in foreign net investments that were unhedged.

As a result of the acquisition of ITC, consolidated earnings and cash flows of Fortis are impacted to a greater extent 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\$1.34 as at December 31, 2016 would increase or decrease earnings per common share of Fortis by approximately 7 cents.

The Corporation may enter into forward foreign exchange contracts and utilize certain derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past. There is no guarantee that such hedging strategies, if adopted, will be effective. 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 Corporation's business, results of operations, financial condition and cash flows.***

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 Corporation's business, results of operations, financial condition and cash flows.

The results of the 2016 election in the United States, including the Republican Party securing the Presidency and control of Congress, will likely result in some tax reform, including a change in tax rates. The specific draft legislation proposing tax reform is expected to be submitted to Congress early to mid-2017 and could be enacted by the end of 2017. If the proposed tax reform is passed, this change in legislation could affect the results of operations, financial condition and cash flows of the Corporation's US subsidiaries.

***Certain of the Corporation's subsidiaries are subject to counterparty default risks. The Corporation and its subsidiaries are exposed to 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 results of operations, financial condition and cash flows of these subsidiaries.***

ITC derives approximately 70% 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. As required under regulation, FortisAlberta minimizes its gross exposure associated with retailer billings by obtaining from the retailer either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson, FortisBC Energy and Aitken Creek may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. These subsidiaries evaluate the creditworthiness of customers in accordance with established credit approval practices. Non-performance by counterparties could have an adverse effect on the results of operations, financial condition and cash flows of these 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. In recent years, there has been a decline in the percentage of new homes installing gas compared with the total number of dwellings being built throughout British Columbia.

---

***A disruption in the wholesale energy markets or failure by an energy or fuel supplier could have an adverse effect on the Corporation and its subsidiaries.***

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, results of operations, financial condition and cash flows.***

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 which 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 and operations of TEP.

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

The emergence of initiatives designed to reduce greenhouse gas emissions and control or limit the effects of global warming and overall 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's 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.

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 2016, the implementation of the Clean Power Plan was stayed pending judicial review. At present, the future of the Clean Power Plan under President Trump's administration is highly uncertain. The utilities continue to assess the impact that such legislative changes may have on future operations, as well as the costs to comply with these 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. If any of the coal-fired generation plants, or coal-handling facilities, from which the utilities obtain power are closed prior to the end of their useful life in response to recent or future changes in environmental regulation, the utilities could be required to recognize an impairment of their assets and incur additional expenses, relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any such generating facilities may force the Corporation's utilities to incur higher costs for replacement capacity and energy, which may not be recovered in customer rates. 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' T&D 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 Corporation's subsidiaries.

***The Corporation's failure to comply with Section 404(a) of the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley") commencing for the year ended December 31, 2017, and on an ongoing basis, could adversely affect investor confidence and harm its reputation.***

Commencing with the year ended December 31, 2017, the Corporation's internal controls 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 SEC and the Public Company Accounting Oversight Board. In addition, the Corporation's independent auditors will be required to attest to the effectiveness of the Corporation's disclosure and internal controls over financial reporting. The Corporation is currently undergoing an assessment of its internal control procedures to determine whether it is in compliance with Section 404(a) of Sarbanes-Oxley. 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 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 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 and T&D facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the 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 Corporation's results of operations, financial condition and cash flows.

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

***The Corporation's subsidiaries 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 subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada, the United States and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and a competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program will present challenges 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 2016, are described as follows.

**Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern**

Effective January 1, 2016, the Corporation adopted Accounting Standards Update ("ASU") No. 2014-15, which provides guidance on management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. The adoption of this update did not impact the Corporation's consolidated financial statements and related disclosures.

**Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items**

Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-01, which is part of the Financial Accounting Standards Board's ("FASB's") initiative to reduce complexity in accounting standards by eliminating the concept of extraordinary items. The adoption of this update did not impact the Corporation's consolidated financial statements.

**Amendments to the Consolidation Analysis**

Effective January 1, 2016, the Corporation adopted ASU No. 2015-02, which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following regarding limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. The amendments in this update did not materially impact the Corporation's consolidated financial statements, however, did change the Corporation's 51% controlling ownership interest in the Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional disclosure.

**Simplifying the Accounting for Measurement-Period Adjustments**

Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-16, which requires that in a business combination an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Under previous guidance, these adjustments were required to be accounted for retrospectively. The adoption of this update did not impact the Corporation's consolidated financial statements.

**Improvements to Employee Share-Based Payment Accounting**

Effective January 1, 2016, the Corporation early adopted ASU No. 2016-09, which simplifies the accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance requires excess tax benefits and tax deficiencies to be recognized as an income tax benefit or expense in the consolidated statement of earnings. On adoption, using the modified retrospective method, the Corporation recognized a cumulative adjustment of \$16 million related to prior period unrecognized excess tax benefits at UNS Energy, which increased retained earnings and decreased deferred income tax liabilities. In 2016 the adoption of this update also resulted in a \$7 million decrease in income tax expense and decrease in deferred income tax liabilities related to excess tax benefits at ITC from the date of acquisition, largely associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition. The guidance also allows for an accounting policy election to either estimate forfeitures or account for them when they occur. The Corporation elected to account for forfeitures when they occur. This policy election did not have a material impact on the Corporation's consolidated financial statements.

## FUTURE ACCOUNTING PRONOUNCEMENTS

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

### Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update create 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 can be applied consistently across various transactions, industries and capital markets. In 2016 a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted for annual and interim periods beginning after December 15, 2016. The Corporation has elected not to early adopt.

The new guidance permits two methods of adoption: (i) the full retrospective method, under which comparative periods would be restated, and the cumulative impact of applying the standard would be recognized as at January 1, 2017, the earliest period presented; 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, January 1, 2018. The Corporation expects to use the modified retrospective approach, however, it continues to monitor industry developments. Any significant industry developments could change the Corporation's expected method of adoption.

The majority of the Corporation's revenue is generated from energy sales to retail customers based on published tariff rates, as approved by the respective regulators, and from transmission services and is considered to be in the scope of ASU No. 2014-09. Fortis does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the recognition of revenue generated from energy sales to retail customers, or on its remaining material revenue streams; however, the Corporation does expect it will impact its required disclosures. Certain industry specific interpretative issues, including contributions in aid of construction, remain outstanding and the conclusions reached, if different than currently anticipated, could have a material impact on the Corporation's consolidated financial statements and related disclosures. Fortis continues to closely monitor industry developments related to the new standard.

### 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; however, entities will be able to elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes; 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 asset. This update is effective for annual and interim periods beginning after December 15, 2017. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

### 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 and related disclosures.

#### 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. Early adoption is permitted for annual and interim periods beginning after December 15, 2018. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

#### Simplifying the Test for Goodwill Impairment

ASU No. 2017-04, *Simplifying the Test for Goodwill Impairment*, was issued in January 2017 and 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. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a prospective basis. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. Fortis expects to early adopt this update in 2017; however, does not expect that it will have a material impact on its consolidated financial statements and related disclosures.

## 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 (\$ millions)	2016		2015	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt, including current portion	21,219	22,523	11,244	12,614
Waneta Partnership promissory note	59	61	56	59

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

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

<b>Financial Instruments Carried at Fair Value</b>			
<i>(\$ millions)</i>	<b>Fair value hierarchy</b>	<b>2016</b>	2015
<b>Assets</b>			
Energy contracts subject to regulatory deferral <sup>(1) (2) (3)</sup>	Levels 1/2/3	<b>19</b>	7
Energy contracts not subject to regulatory deferral <sup>(1) (2)</sup>	Level 3	<b>3</b>	2
Interest rate swaps - cash flow hedges <sup>(4)</sup>	Level 2	<b>11</b>	—
Available-for-sale investment	Level 1	<b>—</b>	33
Assets held for sale	Level 2	<b>—</b>	9
Other investments <sup>(5)</sup>	Level 1	<b>69</b>	12
<b>Total gross assets</b>		<b>102</b>	63
Less: Counterparty netting not offset on the balance sheet <sup>(6)</sup>		<b>(9)</b>	(6)
<b>Total net assets</b>		<b>93</b>	57
<b>Liabilities</b>			
Energy contracts subject to regulatory deferral <sup>(1) (2) (7)</sup>	Levels 2/3	<b>26</b>	78
Energy contracts not subject to regulatory deferral <sup>(1)</sup>	Level 2	<b>9</b>	—
Interest rate swaps - cash flow hedges <sup>(4)</sup>	Level 2	<b>3</b>	5
<b>Total gross liabilities</b>		<b>38</b>	83
Less: Counterparty netting not offset on the balance sheet <sup>(6)</sup>		<b>(9)</b>	(6)
<b>Total net liabilities</b>		<b>29</b>	77

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

<sup>(2)</sup> Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

<sup>(3)</sup> As at December 31, 2016, includes \$1 million - level 1, \$13 million - level 2 and \$5 million - level 3 (December 31, 2015 - \$2 million - level 2 and \$5 million - level 3)

<sup>(4)</sup> The fair value of the Corporation's interest rate swaps is recognized in accounts receivable and other current assets, accounts payable and other current liabilities and long-term other liabilities.

<sup>(5)</sup> Included in long-term other assets on the consolidated balance sheet

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

<sup>(7)</sup> As at December 31, 2016, includes \$21 million - level 2 and \$5 million - level 3 (December 31, 2015 - \$1 million - level 1, \$52 million - level 2 and \$25 million - level 3)

## Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments is the estimate of the amounts that the Corporation would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

### *Energy Contracts Subject to Regulatory Deferral*

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

Central Hudson holds 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 contract premiums to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at December 31, 2016, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recognized in earnings. As at December 31, 2016, unrealized losses of \$19 million (December 31, 2015 - \$74 million) were recognized in regulatory assets and unrealized gains of \$12 million were recognized in regulatory liabilities (December 31, 2015 - \$3 million).

#### *Energy Contracts Not Subject to Regulatory Deferral*

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

Aitken Creek holds gas supply contract premiums and 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 provided by third parties. The unrealized gains and losses on these derivative instruments are recognized in earnings. As at December 31, 2016, unrealized losses totalled \$9 million (\$6 million after tax).

#### *Cash Flow Hedges*

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on capital lease obligations.

ITC holds forward-starting interest rate swaps, effective January 2018 and expiring in 2028, with notional amounts totalling US\$100 million. The agreements include a mandatory early termination provision and will be terminated no later than the effective date. The interest rate swaps manage the interest rate risk associated with the forecasted future issuance of fixed-rate debt related to the refinancing of maturing US\$385 million long-term debt due in January 2018. As at December 31, 2016, the unrealized gain on the derivatives was \$11 million (US\$8 million).

The unrealized gains and losses on 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 \$5 million. Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

## Volume of Derivative Activity

As at December 31, 2016, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity Contracts		2017	2018	2019	2020	2021	There-after
	(year)	(#)						
<b>Energy contracts subject to regulatory deferral:</b>								
Electricity swap contracts (GWh)	2019	8	1,089	657	438	—	—	—
Electricity power purchase contracts (GWh)	2017	39	1,252	—	—	—	—	—
Gas swap and option contracts (PJ)	2019	108	20	11	4	—	—	—
Gas supply contract premiums (PJ)	2024	85	82	45	26	22	22	43
<b>Energy contracts not subject to regulatory deferral:</b>								
Long-term wholesale trading contracts (GWh)	2017	18	2,058	—	—	—	—	—
Gas supply contract premiums (PJ)	2017	226	15	—	—	—	—	—
Gas swap contracts (PJ)	2017	7	4	—	—	—	—	—

## CRITICAL ACCOUNTING ESTIMATES

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

**Regulation:** Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and 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, 2016, Fortis recognized a total of \$2.9 billion in regulatory assets (December 31, 2015 - \$2.5 billion) and \$2.2 billion in regulatory liabilities (December 31, 2015 - \$1.6 billion). The increase in regulatory assets and liabilities from December 31, 2015 was mainly due to the acquisition of ITC. For a 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, 2016, the Corporation's consolidated capital assets and intangible assets were approximately \$30.3 billion, or approximately 63% of total consolidated assets, compared to approximately \$20.1 billion, or approximately 70% of total consolidated assets, as at December 31, 2015. Depreciation and amortization was \$983 million for 2016 compared to \$873 million for 2015.

The majority of the Corporation's regulated utilities accrue estimated non-asset retirement obligation ("ARO") removal costs in depreciation, with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. The estimate of non-ARO removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2016 was \$1.2 billion, an increase of \$0.1 billion from \$1.1 billion as at December 31, 2015, mainly due to the acquisition of ITC.

Changes in depreciation rates, resulting from a change in the estimated service life or removal costs, could have a significant impact on the Corporation's consolidated depreciation and amortization expense.

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

**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. No such event or change in circumstances occurred during 2016 or 2015.

As at December 31, 2016, consolidated goodwill totalled approximately \$12.4 billion (December 31, 2015 - \$4.2 billion). The increase in goodwill was driven by the acquisition of ITC.

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 12 reporting units that were allocated goodwill at the respective dates of acquisition by Fortis. As at October 1, 2016, the Corporation completed its assessment of goodwill for 11 reporting units and, upon acquisition of ITC in October 2016, a purchase price allocation and associated goodwill impairment assessment was completed.

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 determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

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 exceeded their respective carrying value and, therefore, no impairment provision was required in 2016 or 2015.

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

**Employee Future Benefits:**

*Defined Benefit Pension Plans*

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

The expected weighted average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2017, is 5.97%, which is down from 6.25% used for 2016. The decrease in the average long-term rate of return reflects shifting of plan assets from equities to fixed income assets and lower expected returns from fixed income investments. The defined benefit pension plan assets experienced total positive returns of approximately \$187 million in 2016 compared to expected positive returns of \$145 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, 2016, and to determine net pension cost for 2017, is 4.00%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2015, and to determine net pension cost for 2016, of 4.21%. 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. In 2015, newly acquired ITC, along with UNS Energy, adopted the spot rate methodology for determining net pension cost for future years.

There was a \$9 million decrease in consolidated defined benefit net pension cost for 2016 compared to 2015, mainly due to lower amortization of actuarial losses for 2016 compared to 2015, partially offset by additional expenses related to the acquisition of ITC. Any increases or decreases in defined benefit net pension cost at the regulated utilities for 2017 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 2016 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2016 Audited Consolidated Financial Statements.

<b>Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate</b>		
Year Ended December 31, 2016		
<b>(Decrease) increase</b>	<b>Net pension</b>	<b>Projected benefit</b>
<i>(\$ millions)</i>	<b>benefit cost</b>	<b>obligation <sup>(1)</sup></b>
Impact of increasing the rate of return assumption by 100 basis points	(24)	-
Impact of decreasing the rate of return assumption by 100 basis points	19	(52)
Impact of increasing the discount rate assumption by 100 basis points	(36)	(396)
Impact of decreasing the discount rate assumption by 100 basis points	48	490

<sup>(1)</sup> At FortisBC Energy and FortisBC Electric, certain defined benefit pension plans have pension indexing provisions which provide for a portion of investment returns to be allocated in order to provide for indexing of pension benefits. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation. The direction of the impact of a change in the rate of return assumption at FortisBC Energy and FortisBC Electric is also the result of the methodology for determining the pension indexing assumption.

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

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made. Any difference between the cash payments made during the year and the cost incurred during the year is deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions result in changes in regulatory assets and regulatory liabilities for FortisAlberta. 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, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2016, for all defined benefit pension plans, the Corporation had consolidated projected benefit obligations of \$3.0 billion (December 31, 2015 - \$2.8 billion) and consolidated plan assets of \$2.6 billion (December 31, 2015 - \$2.5 billion), for a consolidated funded status in a liability position of \$0.4 billion (December 31, 2015 - \$0.4 billion). In 2016 the Corporation recognized consolidated net pension benefit cost of \$88 million (2015 - \$97 million).

*OPEB Plans*

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

The OPEB plan assets at ITC, UNS Energy and Central Hudson experienced positive returns of \$13 million in 2016 compared to expected positive returns of approximately \$12 million.

The following table provides the sensitivities associated with a 100 basis point change in the health care cost trend rate and the discount rate on 2016 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2016 Audited Consolidated Financial Statements.

<b>Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate</b>		
Year Ended December 31, 2016		
<b>Increase (decrease)</b> <i>(\$ millions)</i>	<b>Net OPEB cost</b>	<b>Accumulated benefit obligation</b>
Impact of increasing the health care cost trend rate assumption by 100 basis points	12	89
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(8)	(71)
Impact of increasing the discount rate assumption by 100 basis points	(6)	(91)
Impact of decreasing the discount rate assumption by 100 basis points	9	113

ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net OPEB cost from forecast net OPEB cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2016, for all OPEB plans, the Corporation had consolidated accumulated benefit obligations of \$676 million (December 31, 2015 - \$574 million) and consolidated plan assets of \$252 million (December 31, 2015 - \$181 million), for a consolidated funded status in a liability position of \$424 million (December 31, 2015 - \$393 million). In 2016 the Corporation recognized consolidated net OPEB benefit cost of \$30 million (2015 - \$27 million).

**AROs:** The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. There are uncertainties in estimating future asset retirement costs due to potential external events, such

as changing legislation or regulations and advances in remediation technologies. The Corporation has AROs associated with the remediation of hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, certain distribution system assets and land.

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

As at December 31, 2016, the Corporation's total AROs were \$58 million (December 31, 2015 - \$49 million), and were associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from equipment, the remediation of asbestos, and the remediation of certain generation and photovoltaic assets. The total ARO liability as at December 31, 2016 has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating the Corporation's AROs represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from current assumptions. The AROs may change from period to period because of changes in the estimates.

**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, 2016, the amount of accrued unbilled revenue recognized in accounts receivable was approximately \$551 million (December 31, 2015 - \$404 million) on consolidated revenue of \$6.8 billion for 2016 (2015 - \$6.8 billion). The increase in accrued unbilled revenue from December 31, 2015 was mainly due to the acquisition of ITC.

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

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

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

**Central Hudson**

*Asbestos Litigation*

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,363 asbestos cases have been raised, 1,175 remained pending as at December 31, 2016. Of the cases no longer pending against Central Hudson, 2,032 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company’s experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

**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 Coldwater Band’s application for judicial review of the ministerial consent. The Band has appealed that decision. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

**Fortis and ITC**

Following announcement of the acquisition of ITC in February 2016, complaints which named Fortis and other defendants were filed in the Oakland County Circuit Court in the State of Michigan (“Superior Court”) and the United States District Court in and for the Eastern District of Michigan. The complaints generally allege, among other things, that the directors of ITC breached their fiduciary duties in connection with the merger agreement and that ITC, Fortis, FortisUS Inc. and Element Acquisition Sub Inc. aided and abetted those purported breaches. The complaints seek class action certification and a variety of relief including, among other things, unspecified damages, and costs, including attorneys’ fees and expenses. In July 2016 the federal actions were voluntarily dismissed by the federal plaintiffs. The federal plaintiffs reserved the right to make certain other claims, and ITC and the individual members of the ITC board of directors reserved the right to oppose any such claim. The federal plaintiffs have sought a mootness fee application and the parties are currently exploring a mutually satisfactory resolution. In June 2016 the Superior Court granted a motion for summary disposition dismissing the aiding and abetting claims asserted against Fortis, FortisUS Inc. and Element Acquisition Sub Inc. In January 2017 the Superior Court issued a revised scheduling order, which, among other things, requires the parties, including ITC, to complete discovery by May 2017, and set a trial date for September 2017. A hearing on the plaintiff’s motion for class certification was held on February 9, 2017. A hearing on a motion of the defendants for summary disposition has been scheduled for March 2017. The outcome of these lawsuits cannot be predicted with any certainty and, accordingly, no amount has been accrued in the consolidated financial statements.

**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 2016 or 2015.

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 2016 and 2015 are summarized in the following table.

Years Ended December 31 (\$ millions)	2016	2015
Sale of capacity from Waneta Expansion to FortisBC Electric	45	30
Sale of energy from BECOL to Belize Electricity	33	30
Lease of gas storage capacity from Aitken Creek to FortisBC Energy	17	—

As at December 31, 2016, accounts receivable on the Corporation's consolidated balance sheet included approximately \$16 million due from Belize Electricity (December 31, 2015 - \$5 million), in which Fortis holds a 33% equity investment.

From time to time, the Corporation provides short-term financing to certain of its subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements, bearing interest at rates that approximate the Corporation's cost of short-term borrowing, and provides long-term financing to certain of its subsidiaries, bearing interest at rates that approximate the Corporation's cost of long-term debt. There were no inter-segment loans outstanding as at December 31, 2016 (December 31, 2015 - \$48 million) and total interest charged in 2016 was less than \$1 million (2015 - \$17 million).

## SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2016, 2015 and 2014.

<b>Selected Annual Financial Information</b>			
Years Ended December 31			
<i>(\$ millions, except per share amounts)</i>			
	<b>2016</b>	2015	2014
Revenue	<b>6,838</b>	6,757	5,401
Net earnings	<b>713</b>	840	390
Net earnings attributable to common equity shareholders	<b>585</b>	728	317
Basic earnings per common share	<b>1.89</b>	2.61	1.41
Diluted earnings per common share	<b>1.89</b>	2.59	1.40
Total assets	<b>47,904</b>	28,804	26,233
Long-term debt (excluding current portion)	<b>20,817</b>	10,784	9,911
Preference shares	<b>1,623</b>	1,820	1,820
Common shareholders' equity	<b>12,974</b>	8,060	6,871
Dividends declared per common share	<b>1.55</b>	1.43	1.30
Dividends declared per First Preference Share, Series E <sup>(1)</sup>	<b>0.6126</b>	1.2250	1.2250
Dividends declared per First Preference Share, Series F	<b>1.2250</b>	1.2250	1.2250
Dividends declared per First Preference Share, Series G	<b>0.9708</b>	0.9708	0.9708
Dividends declared per First Preference Share, Series H <sup>(2)</sup>	<b>0.6250</b>	0.7344	1.0625
Dividends declared per First Preference Share, Series I <sup>(2)</sup>	<b>0.4874</b>	0.3637	—
Dividends declared per First Preference Share, Series J	<b>1.1875</b>	1.1875	1.1875
Dividends declared per First Preference Share, Series K	<b>1.0000</b>	1.0000	1.0000
Dividends declared per First Preference Share, Series M <sup>(3)</sup>	<b>1.0250</b>	1.0250	0.4613

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

<sup>(2)</sup> 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%.

<sup>(3)</sup> The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 and are entitled to receive cumulative dividends in the amount of \$1.0250 per share per annum for the first five years.

**2016/2015:** Revenue increased \$81 million, or 1.2%, from 2015 and net earnings attributable to common equity shareholders were \$585 million, or \$1.89 per common share, compared to \$728 million, or \$2.61 per common share, in 2015. For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders, and earnings per common share, refer to the "Summary Financial Highlights" and "Consolidated Results of Operations" sections of this MD&A.

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.

**2015/2014:** Revenue increased \$1,356 million, or 25.1%, from 2014. The increase in revenue was driven by the acquisition of UNS Energy in August 2014. Favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion and higher base electricity rates at the Canadian Regulated Electric Utilities also contributed to the increase. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets in 2015.

Net earnings attributable to common equity shareholders were \$728 million in 2015 compared to \$317 million in 2014. Results for both years were impacted by adjusting items, largely associated with the sale of commercial real estate and hotel assets in 2015 and the acquisition of UNS Energy in 2014. Earnings for 2015 were favourably impacted by an after-tax net gain of \$133 million on the sale of commercial real estate, hotel and non-regulated generation assets and a positive capital tracker revenue adjustment of \$9 million at FortisAlberta, partially offset by the loss on the settlement of expropriation matters in Belize of \$9 million. Acquisition-related expenses and fees associated with the acquisition of ITC totalled \$7 million in 2015, compared to \$39 million related to the acquisition of UNS Energy in 2014. In addition, earnings in 2014 were unfavourably impacted by interest expense of \$51 million after tax associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy. A \$13 million foreign exchange gain was recognized in 2015 compared to \$8 million in 2014. In addition, earnings for 2014 included \$5 million associated with discontinued operations.

Excluding the above-noted impacts, adjusted net earnings attributable to common equity shareholders for 2015 were \$589 million, an increase of \$195 million from \$394 million for 2014. The increase was driven by a full year of earnings from UNS Energy. Earnings contribution of \$22 million from the Waneta Expansion, which came online in early April 2015, rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta, a higher AFUDC at FortisBC Energy, the resetting of customer rates at Central Hudson, effective July 1, 2015, and the continued strength of the US dollar relative to the Canadian dollar also increased earnings year over year. The increase in adjusted earnings was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy, and lower earnings contribution from non-utility assets due to the sale of the commercial real estate and hotel assets.

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

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

## FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2016 and 2015.

<b>Summary of Electricity and Energy Sales and Gas Volumes</b>			
Fourth Quarters Ended December 31 ( <i>Unaudited</i> )	2016	2015	Variance
<b>Regulated Electric &amp; Gas Utilities - United States</b>			
UNS Energy - Electricity Sales ( <i>GWh</i> )	3,356	3,562	(206)
UNS Energy - Gas Volumes ( <i>PJ</i> )	4	4	—
Central Hudson - Electricity Sales ( <i>GWh</i> )	1,195	1,160	35
Central Hudson - Gas Volumes ( <i>PJ</i> )	6	5	1
<b>Regulated Gas &amp; Electric Utilities - Canadian</b>			
FortisBC Energy ( <i>PJ</i> )	67	62	5
FortisAlberta ( <i>GWh</i> )	4,352	4,188	164
FortisBC Electric ( <i>GWh</i> )	856	836	20
Eastern Canadian ( <i>GWh</i> )	2,207	2,189	18
<b>Regulated Electric Utilities - Caribbean (<i>GWh</i>)</b>	<b>205</b>	201	4
<b>Non-Regulated - Energy Infrastructure (<i>GWh</i>)</b>	<b>115</b>	122	(7)

### Electricity and Energy Sales

The increase in electricity sales was driven by higher energy deliveries at FortisAlberta, due to higher average consumption by oil and gas customers, higher average consumption by residential, commercial and farm and irrigation customers due to changes in weather, and growth in the number of customers. Higher electricity sales at most of the other regulated electric utilities, mainly due to changes in weather, were offset by lower electricity sales at UNS Energy due to lower mining retail and short-term wholesale sales.

### Gas Volumes

The increase in gas volumes at FortisBC Energy was mainly due to customer growth, higher average consumption by residential and commercial customers due to colder temperatures, and higher gas volumes for transportation customers due to certain customers switching to natural gas compared to alternative fuel sources.

<b>Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders</b>						
Fourth Quarters Ended December 31 (Unaudited)						
(\$ millions, except per share amounts)	Revenue			Net Earnings		
	2016	2015	Variance	2016	2015	Variance
<b>Regulated Electric &amp; Gas Utilities - United States</b>						
ITC	334	—	334	59	—	59
UNS Energy	468	482	(14)	29	26	3
Central Hudson	207	202	5	20	15	5
	<b>1,009</b>	684	325	<b>108</b>	41	67
<b>Regulated Gas &amp; Electric Utilities - Canadian</b>						
FortisBC Energy	393	411	(18)	70	65	5
FortisAlberta	143	140	3	30	29	1
FortisBC Electric	102	99	3	13	8	5
Eastern Canadian	278	273	5	16	15	1
	<b>916</b>	923	(7)	<b>129</b>	117	12
<b>Regulated Electric Utilities - Caribbean</b>						
	<b>76</b>	82	(6)	<b>12</b>	9	3
Non-Regulated - Energy Infrastructure	54	30	24	15	11	4
Non-Regulated - Non-Utility	—	6	(6)	—	1	(1)
Corporate and Other	2	2	—	(75)	(44)	(31)
Inter-Segment Eliminations	(4)	(4)	—	—	—	—
<b>Total</b>	<b>2,053</b>	1,723	330	<b>189</b>	135	54
Basic Earnings per Common Share (\$)				<b>0.49</b>	0.48	0.01
Weighted Average Number of Common Shares Outstanding (# millions)				<b>384.6</b>	280.7	103.9

### Revenue

The increase in revenue was driven by the acquisition of ITC, as well as contribution from Aitken Creek. The increase was partially offset by the flow through in customer rates of lower overall energy supply costs.

### Earnings

The increase in earnings was driven by contribution of \$59 million from ITC, which was reduced by \$22 million in expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition. Strong performance at most of the Corporation's regulated utilities and contribution of \$6 million from Aitken Creek, net of an after-tax \$3 million unrealized loss on the mark-to-market of derivatives, also contributed to higher earnings. The increase was partially offset by higher Corporate and Other expenses. Corporate and Other expenses reflected after-tax acquisition-related expenses of \$32 million in the fourth quarter of 2016, compared to \$7 million in the fourth quarter of 2015, with the remaining increase primarily due to finance charges associated with the acquisition of ITC.

### Earnings per Common Share

The impact of higher earnings was offset 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. Excluding the impacts of acquisition-related expenses in the ITC and Corporate and Other segments, as well as the mark-to-market loss at Aitken Creek, adjusted earnings for the fourth quarter of 2016 were \$246 million, or \$0.64 per common share, compared to \$142 million, or \$0.51 per common share, for the fourth quarter of 2015. The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of ITC, strong performance at most of the Corporation's regulated utilities and contribution from Aitken Creek.

<b>Summary of Consolidated Cash Flows</b>			
Fourth Quarters Ended December 31 ( <i>Unaudited</i> )			
<i>(\$ millions)</i>	<b>2016</b>	2015	Variance
<b>Cash, Beginning of Period</b>	<b>301</b>	347	(46)
<b>Cash Provided by (Used in):</b>			
Operating Activities	<b>475</b>	397	78
Investing Activities	<b>(5,187)</b>	(234)	(4,953)
Financing Activities	<b>4,685</b>	(280)	4,965
Effect of Exchange Rate Changes on Cash and Cash Equivalents	<b>(5)</b>	12	(17)
<b>Cash, End of Period</b>	<b>269</b>	242	27

Cash flow from operating activities was \$78 million higher quarter over quarter. The increase was primarily due to higher cash earnings, driven by the acquisition of ITC, partially offset by the Corporation's acquisition-related expenses. Favourable changes in long-term regulatory deferrals were partially offset by unfavourable changes in working capital.

Cash used in investing activities was \$4,953 million higher quarter over quarter. The increase was driven by the acquisition of ITC in October 2016 for a net cash consideration of approximately \$4.5 billion (US\$3.5 billion). Proceeds received from the sale of hotel assets in October 2015 of \$365 million and an increase in capital expenditures also contributed to the increase. Capital expenditures at ITC of approximately US\$167 million from the date of acquisition were partially offset by lower capital spending at FortisAlberta, FortisBC Energy and UNS Energy.

Cash provided by financing activities was \$4,965 million higher quarter over quarter. The increase was driven by financing activities associated with the acquisition of ITC and higher proceeds from the issuance of long-term debt. The increase was partially offset by higher net repayments of committed credit facility borrowings.

## SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2015 through December 31, 2016. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

<b>Summary of Quarterly Results</b>		<b>Net Earnings</b>		
<i>(Unaudited)</i>		<b>Attributable to</b>		
	<b>Revenue</b>	<b>Common Equity</b>	<b>Earnings per Common Share</b>	
<b>Quarter Ended</b>	<i>(\$ millions)</i>	<b>Shareholders</b>	<b>Basic</b>	<b>Diluted</b>
		<i>(\$ millions)</i>	<i>(\$)</i>	<i>(\$)</i>
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
December 31, 2015	1,723	135	0.48	0.48
September 30, 2015	1,579	151	0.54	0.54
June 30, 2015	1,540	244	0.88	0.87
March 31, 2015	1,915	198	0.72	0.71

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions and associated acquisition-related expenses, and the impact of the sale of non-regulated assets, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity and gas demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric 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 2016/December 2015:** Net earnings attributable to common equity shareholders were \$189 million, or \$0.49 per common share, for the fourth quarter of 2016 compared to earnings of \$135 million, or \$0.48 per common share, for the fourth quarter of 2015. 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 2016/September 2015:** Net earnings attributable to common equity shareholders were \$127 million, or \$0.45 per common share, for the third quarter of 2016 compared to earnings of \$151 million, or \$0.54 per common share, for the third quarter of 2015. The decrease in earnings was primarily due to: \$7 million (US\$5 million) in FERC ordered transmission refunds at UNS Energy, \$19 million in acquisition-related expenses and fees, and a \$1 million unrealized loss on the mark-to-market of derivatives in the third quarter of 2016; a \$5 million positive tax adjustment on the sale of hotel assets, a \$5 million gain on the sale of non-regulated generation assets, and a foreign exchange gain of \$5 million in the third quarter of 2015; partially offset by the \$9 million loss on the settlement of expropriation matters in Belize in the third quarter of 2015. Excluding these items, the \$9 million increase in earnings was mainly due to: (i) strong performance at most of the Corporation's regulated utilities driven by UNS Energy, largely due to the settlement of Springerville Unit 1 matters, and Central Hudson, due to an increase in delivery revenue; (ii) the timing of quarterly earnings at FortisBC Electric compared to the third quarter of 2015; and (iii) contribution of \$2 million from Aitken Creek, which was acquired in early April 2016. The increase was partially offset by: (i) lower earnings at FortisAlberta due to higher operating expenses, a negative capital tracker revenue adjustment as a result of the outcome of the 2016 GCOC Proceeding in Alberta, and lower average energy consumption; (ii) the sale of hotel assets in 2015; and (iii) an increase in Corporate and Other expenses.

**June 2016/June 2015:** Net earnings attributable to common equity shareholders were \$107 million, or \$0.38 per common share, for the second quarter of 2016 compared to earnings of \$244 million, or \$0.88 per common share, for the second quarter of 2015. The decrease in earnings was primarily due to: \$22 million in acquisition-related expenses and fees and a \$2 million unrealized loss on the mark-to-market of derivatives in the second quarter of 2016, and a net gain of \$123 million on the sale of commercial real estate, hotel and non-regulated generation assets in the second quarter of 2015. Excluding these items, the \$10 million increase in earnings was mainly due to: (i) strong performance at most of the Corporation's regulated utilities; (ii) contribution of \$4 million from Aitken Creek, which was acquired in early April 2016; (iii) favourable foreign exchange associated with US dollar-denominated earnings; and (iv) the timing of quarterly earnings at FortisBC Electric compared to the second quarter of 2015. The increase was partially offset by lower earnings at FortisAlberta, due to higher operating expenses and lower average energy consumption, and the sale of commercial real estate and hotel assets in 2015.

**March 2016/March 2015:** Net earnings attributable to common equity shareholders were \$162 million, or \$0.57 per common share, for the first quarter of 2016 compared to earnings of \$198 million, or \$0.72 per common share, for the first quarter of 2015. The decrease in earnings was primarily due to: \$17 million in acquisition-related expenses and \$11 million (US\$8 million) in FERC ordered transmission refunds in the first quarter of 2016, and a positive capital tracker revenue adjustment of \$10 million and a foreign exchange gain of \$9 million in the first quarter of 2015. Excluding these items, the \$11 million increase in net earnings was mainly due to: (i) contribution of \$4 million from the Waneta Expansion, which came online in early April 2015, and increased production in Belize due to higher rainfall; (ii) favourable foreign exchange associated with US dollar-denominated earnings; (iii) a higher AFUDC at FortisBC Energy; and (iv) strong performance from the utilities in the Caribbean. The increase was partially offset by the timing of quarterly earnings at FortisBC Electric compared to the first quarter of 2015, and higher Corporate and Other expenses.

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

**Disclosure Controls and Procedures:** The President and Chief Executive Officer ("CEO") and the Executive Vice President, Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2016 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

**Internal Controls over Financial Reporting:** The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with US GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2016 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2016, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR. Given that Fortis became an SEC registrant in 2016, it has until the year ended December 31, 2017 to ensure that its ICFR are in compliance with the requirements of Section 404(a) of Sarbanes-Oxley, and the related rules of the SEC and the Public Company Accounting Oversight Board.

## OUTLOOK

The Corporation's results for 2017 will benefit from the impact of ITC, the outcome of the TEP general rate case and continued growth of the underlying business. Over the long term, Fortis is well positioned to enhance value for shareholders through the execution of its capital plan, the balance and strength of its diversified portfolio of utility businesses, as well as growth opportunities within its franchise regions.

Over the five-year period through 2021, the Corporation's capital program is expected to be approximately \$13 billion, allowing rate base to reach almost \$30 billion in 2021. Fortis expects this 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 2021. 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 15, 2017, the Corporation had issued and outstanding 401.6 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 15, 2017 is approximately 4.1 million.

Additional information can be accessed at [www.fortisinc.com](http://www.fortisinc.com), [www.sedar.com](http://www.sedar.com), or [www.sec.gov](http://www.sec.gov).