UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

o REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934
OR
x ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
Commission file number: 001-37915

FORTIS INC.

(Exact name of Registrant as specified in its charter)

Newfoundland and Labrador, Canada	**4911**	**98-0352146**
(Province of other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

Fortis Place, Suite 1100
5 Springdale Street
St. John's, Newfoundland and Labrador
Canada A1E 0E4
(Address and telephone number of Registrants principal executive offices)

CT Corporation System
111 Eighth Avenue
New York, New York 10011
(212) 590-9070
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Common Shares, without par value	**New York Stock Exchange**
(Title of Class)	*(Name of exchange on which registered)*

Securities registered or to be registered pursuant to Section 12(g) of the Act:
None
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
None
(Title of Class)

For annual reports, indicate by check mark the information filed with this Form:

x Annual information form x Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

428,460,460 Common Shares as of December 31, 2018

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

Yes x No o

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company o

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. o

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

EXPLANATORY NOTE

Fortis Inc. (the "Corporation" or "Fortis") is a Canadian issuer eligible to file its annual report pursuant to Section 13 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), on Form 40-F pursuant to the multi-jurisdictional disclosure system of the Exchange Act. The Corporation is a "foreign private issuer" as defined in Rule 405 under the Securities Act of 1933, as amended. Equity securities of the Corporation are accordingly exempt from Sections 14(a), 14(b), 14(c), 14(f) and 16 of the Exchange Act pursuant to Rule 3a12-3.

FORWARD LOOKING INFORMATION

This Annual Report on Form 40-F and the exhibits attached hereto (the "Form 40-F") contains forward-looking information within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, collectively referred to as "forward-looking information". Forward-looking information reflects expectations of the Corporation's management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: the satisfaction of the conditions, receipt of approvals and the expected timing of the closing of the sale of the Corporation's interest in the Waneta Expansion hydroelectric project; the Corporation's forecast capital expenditures for the period 2019 to 2023 and potential funding sources for the capital expenditure program; the Corporation's forecast rate base for the period 2019 through 2023; the expectation that long-term sustainable growth in rate base will support continuing growth in earnings and dividends; target average annual dividend growth through 2023; the expectation that allocated revenues recognized by ITC Holdings Corp. ("ITC") from Canadian entities reserving transmission over the Ontario or Manitoba interface are not expected to be material to ITC; the expectation that Tucson Electric Power ("TEP") has sufficient generating capacity, together with existing power purchase agreements ("PPAs") and expected generation plant additions, to satisfy the requirements of its customer base and meet future peak demand requirements; the expectation that changes in energy supply costs may increase electricity prices in a manner that adversely affects Newfoundland Power's sales; TEP's expected share of mine reclamation costs; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to long-term capital in 2019; timing of refund payments stemming from the ITC incentive adder complaint and the expectation that the order will not have a material impact on the Corporation's earnings or cash flows; expected timing of filing of regulatory applications and receipt and outcome of

regulatory decisions; the nature, timing, benefits, funding sources and expected costs of certain capital projects including, without limitation, the ITC Multi-Value Regional Transmission Projects and 34.5 to 69 kilovolt Transmission Conversion Project, UNS Energy Gila River Natural Gas Generating Station Unit 2, Southline Transmission Project and New Mexico Wind Project, FortisBC Energy expansion of the Tilbury liquefied natural gas facility, Lower Mainland Intermediate Pressure System Upgrade, Eagle Mountain Woodfibre Gas Line Project, and Transmission Integrity Management Capabilities Project, and the Wataynikaneyap Transmission Power Project and additional opportunities beyond the base plan; the expectation that subsidiary operating expenses and interest costs will be paid out of subsidiary operating cash flows; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from Fortis; the expectation that maintaining the targeted capital structure of the Corporation's regulated operating subsidiaries will not have an impact on its ability to pay dividends in the foreseeable future; the expectation that cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions will be derived from a combination of borrowings under the Corporation's committed corporate credit facility, proceeds from the issuance of common shares, preference shares and long-term debt, and proceeds from non-core asset sales; expected consolidated fixed-term debt maturities and repayments in 2019 and over the next five years; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout 2019; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.

Forward-looking information involves significant risks, uncertainties and assumptions. The Corporation cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. For additional information with respect to certain of these risks or factors, reference should be made to the information detailed under the heading "Business Risk Management" on page 30 of management's discussion and analysis for the year ended December 31, 2018, which is filed as Exhibit 99.3 to this Form 40-F and incorporated by reference herein (the "Annual MD&A"), and to continuous disclosure materials filed from time to time by the Corporation with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission (the "SEC"). Key risk factors for 2019 include, but are not limited to:

- uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities;
- the impact of fluctuations in foreign exchange rates;
- risk associated with the impacts of less favourable economic conditions on the Corporation's results of operations;
- risk associated with the completion of the Corporation's 2019 capital expenditure program, including completion of major capital projects in the timelines anticipated and at the expected amounts; and
- uncertainty in the timing and access to capital markets to arrange sufficient and cost-effective financing to finance, among other things, capital expenditures and the repayment of maturing debt.

All forward-looking information in this Form 40-F is given as of the date of this Form 40-F and the Corporation disclaims any intention or obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

CURRENCY

The Corporation presents its consolidated financial statements in Canadian dollars unless otherwise specified. All dollar amounts in this Form 40-F are stated in Canadian dollars ("$" or "C$"), except where otherwise indicated. On February 13, 2019, the daily average exchange rate (as reported by the Bank of Canada) of United States dollars ("US$") into Canadian dollars was US$1.00 equals C$1.3240.

CERTIFICATIONS

See Exhibits 99.4, 99.5, 99.6 and 99.7 to this Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities laws. As at December 31, 2018, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the President and Chief Executive Officer and the Executive Vice President, Chief Financial Officer, of the effectiveness of the Corporation's disclosure controls and procedures, as defined in the applicable Canadian and United States securities laws. Based on that evaluation, the President and Chief Executive Officer and the Executive Vice President, Chief Financial Officer concluded that such disclosure controls and procedures are effective as at December 31, 2018.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

The Corporation's management, including the Corporation's President and Chief Executive Officer and the Executive Vice President, Chief Financial Officer, assessed the effectiveness of the Corporation's internal control over financial reporting as at December 31, 2018, based on the criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as at December 31, 2018, the Corporation's internal control over financial reporting was effective.

Deloitte LLP, an independent registered public accounting firm, has audited the Corporation's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2018 filed as Exhibit 99.2 to this Form 40-F (the "Annual Financial Statements") and has included its attestation report on management's assessment of the Corporation's internal control over financial reporting, which is found on page iii of the Annual Financial Statements.

ATTESTATION REPORT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Deloitte LLP's attestation report on management's assessment of the Corporation's internal control over financial reporting is found on page iii of the Annual Financial Statements.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Management regularly reviews its system of internal control over financial reporting and makes changes to the Corporation's processes and systems to improve controls and increase efficiency, while ensuring that the Corporation maintains an effective internal control environment. Changes may include such activities as implementing new, more efficient systems, consolidating activities, and migrating processes.

During the year ended December 31, 2018, there have been no changes in the Corporation's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

NOTICES PURSUANT TO REGULATION BTR

The Corporation did not send any notices required by Rule 104 of Regulation BTR during the year ended December 31, 2018 concerning any equity security subject to a blackout period under Rule 101 of Regulation BTR.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Corporation has a separately designated standing Audit Committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The Audit Committee is composed of Tracey C. Ball (Chair), Lawrence T. Borgard, Maura J. Clark, Margarita K. Dilley, Julie A. Dobson, Douglas J. Haughey and Jo Mark Zurel, as described under "Audit Committee - Members" on page 33 of the Corporation's annual information form for the year ended December 31, 2018, which is filed as Exhibit 99.1 to this Form 40-F and incorporated by reference herein (the "AIF").

AUDIT COMMITTEE FINANCIAL EXPERT

The Board has determined that the Corporation has at least one "audit committee financial expert" (as defined in paragraph (8) of General Instruction B to Form 40-F) and that Tracey C. Ball, Maura J. Clark, Margarita K. Dilley and Jo Mark Zurel are the Corporation's "audit committee financial experts" serving on the Audit Committee of the Board. Each of the Audit Committee financial experts is "independent" under applicable listing standards.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

Deloitte LLP served as the Corporation's independent public accountant for the fiscal years ended December 31, 2017 and 2018. For a description of the total amount billed to the Corporation by Deloitte LLP for services performed in the last two fiscal years by category of service (audit fees, audit-related fees, tax fees and all other fees), see "Audit Committee - External Auditor Service Fees" on page 34 of the AIF.

No audit-related fees, tax fees or other non-audit fees were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

AUDIT COMMITTEE PRE-APPROVAL POLICIES AND PROCEDURES

For a description of the pre-approval policies and procedures of the Corporation's Audit Committee, see "Audit Committee - Pre-Approval Policies and Procedures" on page 34 of the AIF.

CODE OF ETHICS

The Corporation has a "code of ethics" (as defined in paragraph (9) of General Instruction B to Form 40-F) that applies to its Chief Executive Officer, Chief Financial Officer, principal accounting officer, controller and persons performing similar functions. The Corporation's code of ethics is available on the Corporation's website at https://www.fortisinc.com/ or, without charge, upon request from the Corporate Secretary, Fortis Inc., Fortis Place, Suite 1100, 5 Springdale Street, St. John's, Newfoundland and Labrador, Canada A1E 0E4 (telephone (709) 737-2800).

During the fiscal year ended December 31, 2018, the Corporation has not granted a waiver from a provision of its code of ethics to its Chief Executive Officer, Chief Financial Officer, principal accounting officer, controller, or persons performing similar functions.

OFF-BALANCE SHEET ARRANGEMENTS

The Corporation has not entered into any "off-balance sheet arrangements", as defined in General Instruction B(11) to Form 40-F, that have or are reasonably likely to have a current or future effect on the Corporation's financial condition, changes in financial condition, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For tabular disclosure of the Corporation's contractual obligations, see page 19 of the Annual MD&A, under the heading "Liquidity and Capital Resources - Contractual Obligations".

COMPARISON OF NYSE CORPORATE GOVERNANCE RULES

The Corporation is subject to a variety of corporate governance guidelines and requirements enacted by the Toronto Stock Exchange (the "TSX"), the Canadian securities regulatory authorities, the New York Stock Exchange (the "NYSE") and the SEC. The Corporation is listed on the NYSE and, although the Corporation is not required to comply with most of the NYSE corporate governance requirements to which the Corporation would be subject if it were a U.S. corporation, the Corporation's governance practices differ from those required of U.S. domestic issuers in only the following respects. The NYSE rules for U.S. domestic issuers require shareholder approval of all equity compensation plans (as defined in the NYSE rules) regardless of whether new issuances, treasury shares or shares that the Corporation has purchased in the open market are used. The TSX rules require shareholder approval of share compensation arrangements involving new issuances of shares, and of certain amendments to such arrangements, but do not require such approval if the compensation arrangements involve only shares purchased in the open market. The NYSE rules for U.S. domestic issuers also require shareholder approval of certain transactions or series of related transactions that result in the issuance of common shares, or securities convertible into or exercisable for common shares, that have, or will have upon issuance, voting power equal to or in excess of 20% of the voting power outstanding prior to the transaction or if the issuance of common shares, or securities convertible into or exercisable for common shares, are, or will be upon issuance, equal to or in excess of 20% of the number of common shares outstanding prior to the transaction. The TSX rules require shareholder approval of acquisition transactions resulting in dilution in excess of 25%. The TSX also has broad general discretion to require shareholder approval in connection with any issuances of listed securities. The Corporation complies with the TSX rules described in this paragraph.

UNDERTAKING

The Corporation undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the SEC staff, and to furnish promptly, when requested to do so by the SEC staff, information relating to: the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

DISCLOSURE PURSUANT TO SECTION 13(r) OF THE EXCHANGE ACT

In accordance with Section 13(r) of the Exchange Act, the Corporation is required to include certain disclosures in its periodic reports if it or any of its affiliates knowingly engaged in certain specified activities during the period covered by the report. Neither the Corporation nor its affiliates have knowingly engaged in any transaction or dealing reportable under Section 13(r) of the Exchange Act during the year ended December 31, 2018.

INCORPORATION BY REFERENCE

Fortis' Annual Report on Form 40-F (other than the section entitled "Credit Ratings" in Exhibit 99.1 to this Form 40-F) is incorporated by reference into Fortis' Registration Statements on Form S-8 (File No. 333-215777), Form F-3 (File No. 333-218032), Form S-8 (File No. 333-226663) and Form F-10 (File No. 333-228593).

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form of the Corporation for the fiscal year ended December 31, 2018
99.2	Audited Consolidated Financial Statements for the fiscal year ended December 31, 2018
99.3	Management's Discussion and Analysis for the fiscal year ended December 31, 2018
99.4	Chief Executive Officer certification required by Rule 13a-14(a)
99.5	Chief Financial Officer certification required by Rule 13a-14(a)
99.6	Chief Executive Officer certification required by Rule 13a-14(b)
99.7	Chief Financial Officer certification required by Rule 13a-14(b)
99.8	Consent of Deloitte LLP
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Corporation certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

FORTIS INC.

/s/ Jocelyn H. Perry

Jocelyn H. Perry
Executive Vice President, Chief Financial Officer
Date: February 14, 2019

Exhibit 99.1



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2018

February 14, 2019

ANNUAL INFORMATION FORM

For the year ended December 31, 2018
Dated February 14, 2019

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FORWARD-LOOKING INFORMATION

Fortis includes "forward-looking information" in this AIF within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, collectively referred to as "forward-looking information". Forward-looking information included in this AIF reflects expectations of Fortis management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: the satisfaction of the conditions, receipt of approvals and the expected timing of the closing of the sale of the Corporation's interest in the Waneta Expansion; the Corporation's forecast capital expenditures for the period 2019 to 2023; the Corporation's forecast rate base for the period 2019 through 2023; the expectation that long-term sustainable growth in rate base will support continuing growth in earnings and dividends; target average annual dividend growth through 2023; the expectation that allocated revenues recognized by ITC from Canadian entities reserving transmission over the Ontario or Manitoba interface are not expected to be material to ITC; the expectation that TEP has sufficient generating capacity, together with existing PPAs and expected generation plant additions, to satisfy the requirements of its customer base and meet future peak demand requirements; the expectation that changes in energy supply costs may increase electricity prices in a manner that adversely affects Newfoundland Power's sales; and TEP's expected share of mine reclamation costs.

Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; no material capital project and financing cost overrun related to any of the Corporation's capital projects; sufficient human resources to deliver service and execute the capital program; 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 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; no significant changes in government energy plans, environmental laws and regulations that may materially negatively affect the Corporation and its subsidiaries; the ability to obtain and maintain licences and permits; retention of existing service areas; the continued tax deferred treatment of earnings from the Corporation's foreign operations; continued maintenance of information technology infrastructure and no material breach of cybersecurity; continued favourable relations with First Nations; and favourable labour relations.

Forward-looking information involves significant risks, uncertainties and assumptions. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. For additional information with respect to certain of these risks or factors, reference should be made to the MD&A for the year ended December 31, 2018 under the heading "Business Risk Management" and to the continuous disclosure materials filed from time to time by Fortis with Canadian securities regulatory authorities and the Securities and Exchange Commission. Key risk factors for 2019 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; the impact of fluctuations in foreign exchange rates; risk associated with the impacts of less favourable economic conditions on the Corporation's results of operations; risk associated with the completion of the Corporation's 2018 capital expenditure program, including completion of major capital projects in the timelines anticipated and at the expected amounts; and uncertainty in the timing and access to capital markets to arrange sufficient and cost-effective financing to finance, among other things, capital expenditures and the repayment of maturing debt.

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

Conversions

1 litre = 0.22 imperial gallons
1 kilometre = 0.62 miles

Conversion using the above factors on rounded numbers appearing in this AIF may produce small differences from reported amounts as a result.

Some information in this AIF is set forth in metric units and some is set forth in imperial units.

Measurements

GW Gigawatt(s)
GWh Gigawatt hour(s)
km Kilometre(s)
kV Kilovolt(s)
kW Kilowatt(s)
MW Megawatt(s)
MWh Megawatt hour(s)
TJ Terajoule(s)
PJ Petajoule(s)

DEFINITIONS

Financial information in this AIF has been prepared in accordance with US GAAP and is presented in Canadian dollars ($) unless otherwise specified. Except as otherwise noted, the information in this AIF is given as of December 31, 2018.

Certain terms used in this 2018 Annual Information Form are defined below:

"2018 Annual Information Form" or **"AIF"** means this annual information form of the Corporation in respect of the year ended December 31, 2018;

"ACGS" means Aitken Creek Gas Storage ULC;

"Aitken Creek" means the Aitken Creek natural gas storage facility;

"Algoma Power" means Algoma Power Inc.;

"APS" means Arizona Public Service Company;

"AUC" means the Alberta Utilities Commission;

"BC Hydro" means the BC Hydro and Power Authority;

"BCUC" means the British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"Board" means the Board of Directors of the Corporation;

"BPC" means Brilliant Power Corporation;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"Central Hudson" means Central Hudson Gas & Electric Corporation;

"CH Energy Group" means CH Energy Group, Inc.;

"CMS" means Consumers Energy Company;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

"Corporation" means Fortis Inc.;

"CPA" means the Canal Plant Agreement;

"CBT" means Columbia Basin Trust;

"CPC" means Columbia Power Corporation;

"DBRS" means DBRS Limited;

"DTE" means DTE Electric Company;

"EDGAR" means the SEC's system for Electronic Data Gathering, Analysis and Retrieval available at www.sec.gov;

"FERC" means the Federal Energy Regulatory Commission;

"FHI" means FortisBC Holdings Inc.;

"Fitch" means Fitch Ratings Inc.;

"Fortis" means Fortis Inc.;

"FortisAlberta" means FortisAlberta Inc.;

"FortisAlberta Holdings" means FortisAlberta Holdings Inc.;

"FortisBC Electric" means, collectively, the operations of FortisBC Inc. and its parent company, FortisBC Pacific Holdings Inc.;

"FortisBC Energy" means FortisBC Energy Inc.;

"FortisOntario" means FortisOntario Inc.;

"FortisTCI" means, collectively, FortisTCI Limited and Turks and Caicos Utilities Limited;

"FortisUS" means FortisUS Inc.;

"FortisUS Holdings" means FortisUS Holdings Nova Scotia Limited;

"FortisWest" means FortisWest Inc.;

"GHG" means greenhouse gas;

"GIC" means GIC Private Limited;

"GSMIP" means the Gas Supply Mitigation Incentive Plan of FortisBC Energy;

"IESO" means the Independent Electricity System Operator of Ontario;

"IPL" means Interstate Power and Light Company;

"ITC" means ITC Holdings together with all of its subsidiaries;

"ITC Great Plains" means ITC Great Plains, LLC;

"ITC Holdings" means ITC Holdings Corp.;

"ITC Interconnection" means ITC Interconnection LLC;

"ITC Investment Holdings" means ITC Investment Holdings Inc.;

"ITC Midwest" means ITC Midwest LLC;

"ITC MISO Regulated Operating Subsidiaries" means ITCTransmission, METC and ITC Midwest together;

"ITCTransmission" means International Transmission Company;

"ITC Regulated Operating Subsidiaries" means collectively, ITCTransmission, METC, ITC Midwest, ITC Great Plains and ITC Interconnection;

"Maritime Electric" means Maritime Electric Company, Limited;

"MD&A" means the Corporation's Management Discussion and Analysis in respect of the year ended December 31, 2018;

"METC" means Michigan Electric Transmission Company;

"**MISO**" means the Midcontinent Independent System Operator, Inc.;

"Moody's" means Moody's Investors Service, Inc.;

"NB Power" means New Brunswick Power Corporation;

"NL Hydro" means Newfoundland and Labrador Hydro Corporation;

"Newfoundland Power" means Newfoundland Power Inc.;

"NYSE" means the New York Stock Exchange;

"PEI" means Prince Edward Island;

"PNM" means Public Service Company of New Mexico;

"PPA" means power purchase agreement;

"PUB" means the Newfoundland and Labrador Board of Commissioners of Public Utilities;

"S&P" means Standard & Poor's Financial Services LLC;

"SEC" means the United States Securities and Exchange Commission;

"SEDAR" means the System for Electronic Document Analysis and Retrieval of the Canadian Securities Administrators available at www.sedar.com;

"SPP" means Southwest Power Pool, Inc.;

"SRP" means Salt River Project Agricultural Improvement and Power District;

"T&D" means transmission and distribution;

"TEP" means Tucson Electric Power Company;

"TransCanada" means TransCanada Pipelines Limited;

"TSX" means the Toronto Stock Exchange;

"UNS Electric" and **"UNSE"** mean UNS Electric, Inc.;

"UNS Energy" means UNS Energy Corporation;

"UNS Gas" means UNS Gas, Inc.;

"Waneta Expansion" means the 335-MW Waneta Expansion hydroelectric generating facility;

"Waneta Partnership" means the Waneta Expansion Limited Partnership; and

"Wataynikaneyap Partnership" means the Wataynikaneyap Power Limited Partnership.

CORPORATE STRUCTURE

Name and Incorporation

Fortis Inc. is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987. The articles of continuance of the Corporation were amended to: (i) change its name to Fortis on October 13, 1987; (ii) set out the rights, privileges, restrictions and conditions attached to the common shares on October 15, 1987; (iii) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (iv) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (v) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (vi) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (vii) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (viii) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (ix) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; (x) designate 9,200,000 First Preference Shares, Series G on May 20, 2008; (xi) designate 10,000,000 First Preference Shares, Series H and 10,000,000 First Preference Shares, Series I on January 20, 2010; (xii) designate 8,000,000 First Preference Shares, Series J on November 8, 2012; (xiii) designate 12,000,000 First Preference Shares, Series K and 12,000,000 First Preference Shares, Series L on July 11, 2013; and; (xiv) designate 24,000,000 First Preference Shares, Series M and 24,000,000 First Preference Shares, Series N on September 16, 2014.

The corporate head office and registered office of Fortis is located at Fortis Place, Suite 1100, 5 Springdale Street, P.O. Box 8837, St. John's, Newfoundland and Labrador, Canada, A1B 3T2.

Inter-Corporate Relationships

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at February 14, 2019. The principal subsidiaries together comprise approximately 88% of the Corporation's consolidated assets as at December 31, 2018 and approximately 84% of the Corporation's 2018 consolidated revenue. This table excludes certain subsidiaries, the assets and revenues of which did not individually exceed 10%, or in the aggregate exceed 20% of the total consolidated assets or total consolidated revenues of the Corporation as at December 31, 2018.

Subsidiary	Jurisdiction of Incorporation	Votes attaching to voting securities beneficially owned, controlled or directed by the Corporation (%)
ITC *(1)*	Michigan, United States	80.1
UNS Energy *(2)*	Arizona, United States	100
Central Hudson *(3)*	New York, United States	100
FortisBC Energy *(4)*	British Columbia, Canada	100
FortisAlberta *(5)*	Alberta, Canada	100
Newfoundland Power *(6)*	Newfoundland and Labrador, Canada	95

(1) ITC Holdings, a Michigan corporation, owns all of the shares of ITC Great Plains, ITC Interconnection, ITC Midwest, ITCTransmission and METC. ITC Investment Holdings, a Michigan corporation, owns all of the shares of ITC Holdings. FortisUS, a Delaware corporation, owns 80.1% of the voting securities of ITC Investment Holdings. FortisUS Holdings, a Canadian Corporation, owns all of the shares of FortisUS. Fortis owns all of the shares of FortisUS Holdings. 19.9% of the voting securities of ITC Investment Holdings are owned by an affiliate of GIC.

(2) UNS Energy owns all of the shares of TEP, UNS Electric and UNS Gas. FortisUS owns all of the shares of UNS Energy.

(3) CH Energy Group, Inc., a New York corporation, owns all of the shares of Central Hudson. FortisUS owns all of the shares of CH Energy Group.

(4) FHI, a British Columbia corporation, owns all of the shares of FortisBC Energy. Fortis owns all of the shares of FHI.

(5) FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.

(6) Fortis owns all of the common shares and certain of the First Preference Shares, Series A, B, D and G of Newfoundland Power, which, as at February 14, 2019, represent 95% of its voting securities. The remaining 5% of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G, which are primarily held by the public.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Fortis is a leader in the North American regulated electric and gas utility industry, with 2018 revenue of $8.4 billion and total assets of $53 billion as at December 31, 2018. The Corporation's 8,800 employees serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. In 2018 the Corporation's electricity systems met a combined peak demand of 33,295 MW and its gas distribution systems met a peak day demand of 1,599 TJ.

Three-Year History

Over the past three years, Fortis has experienced significant growth in its business operations. Total assets have almost doubled from $28.8 billion as at December 31, 2015 to $53.1 billion as at December 31, 2018. The Corporation's shareholders' equity has also grown significantly from $10.4 billion as at December 31, 2015 to $18.5 billion as at December 31, 2018. Net earnings attributable to common equity shareholders have increased from $728 million in 2015 to $1,100 million in 2018.

The growth in business operations reflects the Corporation's profitable growth strategy for its principal regulated utilities. This strategy includes a combination of organic growth through the Corporation's consolidated capital expenditure program and growth from acquisitions.

In April 2016 the Corporation completed the acquisition of ACGS for approximately $349 million, plus the cost of working gas inventory. ACGS owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company. Aitken Creek is the only underground 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.

In October 2016 the Corporation and GIC acquired all of the outstanding common shares of ITC, the largest independent transmission company in the U.S., for an aggregate purchase price of approximately $15.7 billion (US$11.8 billion) on closing, including approximately $6.3 billion (US$4.8 billion) of ITC consolidated indebtedness. ITC is a subsidiary of Fortis, with an affiliate of GIC owning a 19.9% minority interest in ITC.

In connection with the acquisition of ITC, Fortis became an SEC registrant in May 2016 and in October 2016 the Corporation's common shares commenced trading on the NYSE. The Corporation filed a business acquisition report in connection with its acquisition of ITC on SEDAR and EDGAR on November 23, 2016.

In January 2019 the Corporation announced it has entered into a definitive agreement with CBT and CPC to sell its 51% interest in the Waneta Expansion for approximately $1 billion. Fortis expects the transaction to close in the second quarter of 2019 following the satisfaction of customary closing conditions and the receipt of routine approvals. The sale of the Corporation's interest in the Waneta Expansion completes the asset sale portion of the Corporation's capital funding strategy.

The Corporation's gross consolidated capital expenditures for 2018 were approximately $3.2 billion. Over the past three years, including 2018, gross consolidated capital expenditures totalled $8.3 billion. Organic asset growth has been driven by the capital expenditure programs at the Corporation's regulated utilities. Organic growth in non-regulated operations has been driven by the acquisition of Aitken Creek in April 2016.

Outlook

Over the long term, Fortis is well positioned to enhance value for shareholders through the execution of its capital program, the balance and strength of its diversified portfolio of utility businesses, as well as growth opportunities within its service territories.

The Corporation's $17.3 billion five-year capital program is expected to increase rate base from $26.1 billion in 2018 to approximately $32.0 billion in 2021 and $35.5 billion in 2023, translating into three and five-year compound annual growth rates of 7.1% and 6.3%, respectively. The five-year capital program addresses system capacity and improves safety and reliability for the benefit of customers through investments that improve and automate the electricity grid, address natural gas system capacity and gas line network integrity, increase cyber protection and allow the grid to deliver cleaner energy.

Fortis is focused on securing further growth opportunities at its subsidiaries, which include the ITC Lake Erie Connector Project, gas infrastructure opportunities at FortisBC Energy and renewable energy investments, including storage, at UNS Energy.

Fortis expects long-term sustainable growth in rate base to support continuing growth in earnings and dividends. Fortis is targeting average annual dividend growth of 6% through 2023. 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 program, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

DESCRIPTION OF THE BUSINESS

Fortis is principally a North American electric and gas utility holding company. Most of the Corporation's regulated utilities operate as the sole supplier of electricity and/or gas within their respective service territories. Fortis is primarily an energy delivery company with 93% of its assets dedicated to energy delivery. The Corporation's regulated utilities own and operate facilities that generate, transmit and/or distribute electricity and/or natural gas to their customers. Competition in the regulated electric business is primarily from alternative energy sources and on-site generation by industrial customers. The Corporation faces competition in its transmission business which may restrict its ability to grow this business outside of its established service territories.

At the Corporation's regulated gas utilities, natural gas primarily competes with electricity for space and hot water heating load. In addition to other price comparisons, upfront capital cost differences between electric and natural gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of natural gas on a fully-costed basis.

As the Corporation's subsidiaries operate in various jurisdictions throughout North America, seasonality impacts each utility differently. Most of the annual earnings of the Corporation's gas utilities are realized in the first and fourth quarters due to space-heating requirements in colder weather. Earnings for 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 in the summer.

As at December 31, 2018, approximately 67% of the Corporation's assets were located outside of Canada and approximately 60% of the Corporation's revenue was derived from foreign operations.

The following table summarizes the Corporation's operations and the sections that follow describe the operations of the Corporation's reportable segments.

	Customers	Peak Demand (1)		Electric T&D Lines (km) (2)	Gas T&D Lines (km)	Generating Capacity (MW)	Revenue (millions)	GWh Sales	Gas Volumes (PJ)	Employees
Regulated Utilities										
ITC	—	23,634	MW	25,400	—	—	$ 1,504	—	—	692
UNS Energy	680,000	3,107 93	MW TJ	22,400	5,000	3,377	2,202	17,406	13	2,049
Central Hudson	380,000	1,114 153	MW TJ	15,100	2,350	64	924	5,118	24	1,014
FortisBC Energy	1,030,000	1,353	TJ	—	49,500	—	1,187	—	212	1,846
FortisAlberta	564,000	2,743	MW	88,900	—	—	579	17,154	—	1,110
FortisBC Electric	176,000	663	MW	7,300	—	225	408	3,250	—	525
Other Electric										
Newfoundland Power	268,000	1,362	MW	12,600	—	139	662	5,876	—	623
Maritime Electric	81,000	280	MW	6,100	—	145	203	1,257	—	202
FortisOntario	66,000	257	MW	3,500	—	5	201	1,293	—	206
Caribbean Utilities	30,000	94	MW	750	—	161	258	629	—	236
FortisTCI	15,000	41	MW	650	—	91	88	237	—	173
Non-Regulated										
Energy Infrastructure	—	—		—	—	386 (3)	184	853	—	65
Corporate and Other	—	—		—	—	—	—	—	—	59
Total	3,290,000	33,295 1,599	MW TJ	182,700	56,850	4,593	$ 8,400	53,073	249	8,800

(1) Electric (MW) or gas (TJ)
(2) Circuit km
(3) Includes the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion

Regulated Utilities

ITC

ITC's business consists mainly of the electric transmission operations of the ITC Regulated Operating Subsidiaries. Through ITC's Regulated Operating Subsidiaries, it owns and operates high-voltage systems in Michigan's Lower Peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from generating stations to local distribution facilities connected to ITC's systems. ITC's business strategy is to own, operate, maintain and invest in transmission infrastructure in order to enhance system integrity and reliability, reduce transmission constraints and support new generating resources to interconnect to ITC's transmission system. ITC owns and operates more than 25,000 circuit km of transmission lines.

ITC's Regulated Operating Subsidiaries earn revenues from the use of their transmission systems by customers, including investor-owned utilities, municipalities, cooperatives, power marketers and alternative energy suppliers. As independent transmission companies, ITC's Regulated Operating Subsidiaries are subject to rate regulation only by FERC. The rates charged are established using cost-based formula rates.

ITC's principal transmission service customers are DTE, CMS and IPL. One or more of these customers together have consistently represented a significant percentage of ITC's operating revenue. Nearly all of ITC's revenues are from transmission customers in the United States. Although ITC may recognize allocated revenues from time to time from Canadian entities reserving transmission over the Ontario or Manitoba interface, these revenues have not been and are not expected to be material to ITC.

Market and Sales

Revenues

ITC derives nearly all of its revenues from transmission, scheduling, control and dispatch services and other related services to DTE, CMS, IPL and other entities, such as alternative electricity suppliers, power marketers and other wholesale customers, as well as from transaction-based capacity reservations on ITC's transmission systems. MISO and SPP are responsible for billing and collecting the majority of ITC's transmission service revenues. As the billing agent for ITC's MISO Regulated Operating Subsidiaries and ITC Great Plains, MISO and SPP collect fees for the use of ITC's transmission systems, invoicing customers on a monthly basis.

Network revenues are generated from network customers for their use of ITC's electric transmission systems and are based on the actual revenue requirements as a result of ITC's accounting under its cost-based formula rates that contain a true-up mechanism.

Network revenues at ITC Great Plains include the annual revenue requirements specific to projects that are charged exclusively within one pricing zone within SPP or are classified as direct assigned network upgrades under the SPP tariff and contain a true-up mechanism.

Regional cost-sharing revenues are generated from transmission customers for their use of ITC's MISO Regulated Operating Subsidiaries' network upgrade projects that are eligible for regional cost-sharing under provisions of the MISO tariff, including Multi-Value Projects such as ITCTransmission's Thumb Loop Project. Regional cost-sharing revenues also include revenues collected by transmission customers from other regional transmission organizations outside of MISO to allocate costs of certain transmission plant investments. Additionally, certain projects at ITC Great Plains are eligible for recovery through a region-wide charge under provisions of the SPP tariff. A portion of regional cost-sharing revenues is credited to regional or network customers when calculating the net revenue requirement under ITC's cost-based formula rates.

Point-to-point revenues consist of revenues generated from a type of transmission service for which the customer pays for transmission capacity reserved along a specified path between two points on an hourly, daily, weekly or monthly basis. Point-to-point revenues also include other components pursuant to schedules under the MISO and SPP transmission tariffs. Point-to-point revenues are treated as a revenue credit to network or regional customers and are a reduction to the gross revenue requirement when calculating the net revenue requirement under ITC's cost-based formula rates.

Scheduling, control and dispatch revenues are allocated by MISO to ITC's MISO Regulated Operating Subsidiaries as compensation for the services performed in operating the transmission system. Such services include monitoring of reliability data, current and next day analysis, implementation of emergency procedures and outage coordination and switching.

Other revenues consist of rental revenues, easement revenues, revenues relating to use of jointly owned assets under ITC's transmission ownership and operating agreements and amounts from providing ancillary services to customers. The majority of other revenues are treated as a credit when calculating the net revenue requirement under ITC's cost-based formula rates.

The following table compares the composition of ITC's 2018 and 2017 revenue by customer class.

	Revenue (%)	
	2018	2017
Network revenues	**66.7**	67.4
Regional cost-sharing revenues	**28.9**	28.1
Point-to-point	**1.2**	1.5
Scheduling, control and dispatch	**1.3**	1.1
Other	**1.9**	1.9
Total	**100.0**	100.0

Contracts

ITCTransmission

DTE operates the electric distribution system to which ITCTransmission's transmission system connects. A set of three operating contracts sets forth the terms and conditions related to DTE's and ITCTransmission's ongoing working relationship. These contracts include:

Master Operating Agreement. This agreement governs the primary day-to-day operational responsibilities. The agreement identifies the control area coordination services that ITCTransmission is obligated to provide to DTE and certain generation-based support services that DTE is required to provide to ITCTransmission.

Generator Interconnection and Operation Agreement. This agreement established, re-established and maintains the interconnection of DTE's electricity generating assets with ITCTransmission's transmission system.

Coordination and Interconnection Agreement. This agreement governs the rights, obligations and responsibilities regarding, among other things, the operation and interconnection of DTE's distribution system and ITCTransmission's transmission system, and the construction of new facilities or modification of existing facilities. Additionally, this agreement allocates costs for operation of supervisory, communications and metering equipment.

METC

CMS operates the electric distribution system to which METC's transmission system connects. METC is a party to a number of operating contracts with CMS that govern the operations and maintenance of its transmission system. These contracts include:

Amended and Restated Easement Agreement. Under this agreement, CMS provides METC with an easement to the land on which a majority of METC's transmission towers, poles, lines and other transmission facilities, used to transmit electricity for CMS and others, are located. METC pays CMS a nominal annual rent for the easement and also pays for any rentals, property taxes and other fees related to the property covered by the agreement.

Amended and Restated Operating Agreement. Under this agreement, METC is responsible for maintaining and operating its transmission system, providing CMS with information and access to its transmission system and related books and records, administering and performing the duties of control area operator (that is, the entity exercising operational control over the transmission system) and, if requested by CMS, building connection facilities necessary to permit interaction with new distribution facilities built by CMS.

Amended and Restated Purchase and Sale Agreement for Ancillary Services. Since METC does not own any generating facilities, it must procure ancillary services from third-party suppliers, such as CMS. Currently, under this agreement, METC pays CMS for providing certain generation based services necessary to support the reliable operation of the bulk power grid, such as voltage support and generation capability and capacity to balance loads and generation.

Amended and Restated Distribution-Transmission Interconnection Agreement. This agreement provides for the interconnection of CMS's distribution system with METC's transmission system and defines the continuing rights, responsibilities and obligations of the parties with respect to the use of certain of their own and the other parties' property, assets and facilities.

Amended and Restated Generator Interconnection Agreement. This agreement specifies the terms and conditions under which CMS and METC maintain the interconnection of CMS' generation resources and METC's transmission assets.

ITC Midwest

IPL operates the electric distribution system to which ITC Midwest's transmission system connects. ITC Midwest is a party to a number of operating contracts with IPL that govern the operations and maintenance of its transmission system. These contracts include:

Distribution-Transmission Interconnection Agreement. This agreement governs the rights, responsibilities and obligations of ITC Midwest and IPL, with respect to the use of certain of their own and the other parties' property, assets and facilities and the construction of new facilities or modification of existing facilities.

Large Generator Interconnection Agreement. ITC Midwest, IPL and MISO entered into this agreement to establish, re-establish and maintain the direct electricity interconnection of IPL's electricity generating assets with ITC Midwest's transmission system.

UNS Energy

UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona. It is engaged through its subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 680,000 electricity and gas customers. UNS Energy is primarily comprised of three wholly owned regulated utilities: TEP, UNS Electric and UNS Gas.

TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility that generates, transmits and distributes electricity. TEP serves approximately 425,000 retail customers in a territory comprising approximately 2,991 square km in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP's service area covers a population of over one million people. TEP also sells wholesale electricity to other entities in the western United States.

UNS Electric is a vertically integrated regulated electric utility that generates, transmits and distributes electricity to approximately 97,000 retail customers in Arizona's Mohave and Santa Cruz counties, which have a combined population of approximately 253,000.

TEP and UNS Electric currently own generation resources with an aggregate capacity of 3,377 MW, including 57 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. TEP has sufficient generation capacity that, together with existing PPAs and expected generation plant additions, are expected to satisfy the requirements of its customer base and meet future peak demand requirements. As at December 31, 2018, approximately 37% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility that serves approximately 158,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties, which have a combined population of approximately 731,000.

Market and Sales

UNS Energy's electricity sales were 17,406 GWh in 2018, compared to 14,971 GWh in 2017. Earnings for UNS Energy's electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment. Gas volumes were 13 PJ in 2018 and 2017. Revenue was $2,202 million in 2018, compared to $2,080 million in 2017.

The following table provides the composition of UNS Energy's 2018 and 2017 revenue, electricity sales, and gas volumes by customer class.

	Revenue (%)		GWh Sales (%)		PJ Volumes (%)	
	2018	2017	**2018**	2017	**2018**	2017
Residential	**37.6**	38.1	**26.9**	31.1	**58.8**	56.4
Commercial	**22.1**	23.1	**16.2**	19.2	**24.5**	24.7
Industrial	**14.4**	14.5	**17.7**	20.3	**2.0**	2.1
Other *(1)*	**25.9**	24.3	**39.2**	29.4	**14.7**	16.8
Total	**100.0**	100.0	**100.0**	100.0	**100.0**	100.0

(1) Includes electricity sales and gas volumes to other entities for resale and revenue from sources other than from the sale of electricity and gas

Power Supply

TEP meets the electricity supply requirements of its retail and wholesale customers with its owned electrical generating capacity of 3,076 MW and its T&D system consisting of approximately 15,900 km of line. In 2018 TEP met a peak demand of 2,682 MW, which includes firm sales to wholesale customers. TEP is a member of a regional reserve-sharing organization and has reliability and power sharing relationships with other utilities.

TEP's generating capacity as of December 31, 2018 is set forth in the following table.

Generation Source	**Unit No.**	**Location**	**Date in Service**	**Total Capacity (MW)**	**Operating Agent**	**TEP's Share (%)**	**TEP's Share (MW)**
Coal							
Springerville Station *(1)*	1	Springerville, AZ	1985	387	TEP	100.0	387
Springerville Station	2	Springerville, AZ	1990	406	TEP	100.0	406
San Juan Station	1	Farmington, NM	1976	340	PNM	50.0	170
Navajo Station *(2)*	1	Page, AZ	1974	750	SRP	7.5	56
Navajo Station *(2)*	2	Page, AZ	1975	750	SRP	7.5	56
Navajo Station *(2)*	3	Page, AZ	1976	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	785	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	785	APS	7.0	55
Natural Gas							
Gila River Power Station *(3)*	2	Gila Bend, AZ	2003	550	SRP	100.0	550
Gila River Power Station	3	Gila Bend, AZ	2003	550	SRP	75.0	413
Luna Generating Station	1	Deming, NM	2006	555	PNM	33.3	185
Sundt Station *(4)*	1	Tucson, AZ	1958	81	TEP	100.0	81
Sundt Station *(4)*	2	Tucson, AZ	1960	81	TEP	100.0	81
Sundt Station	3	Tucson, AZ	1962	104	TEP	100.0	104
Sundt Station	4	Tucson, AZ	1967	156	TEP	100.0	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	50	TEP	100.0	50
DeMoss Petrie		Tucson, AZ	2001	75	TEP	100.0	75
North Loop		Tucson, AZ	2001	94	TEP	100.0	94
Solar							
Utility-Scale Renewables		Various	2002-2017	46	TEP	100.0	46
Total Capacity							**3,076**

(1) Springerville Generating Station Unit 2 is owned by San Carlos Resources Inc., a wholly-owned subsidiary of TEP.

(2) TEP, along with the other participants at the Navajao Generation Station plan to discontinue operations of the generating station by the end of 2019.

(3) In 2017, TEP entered into a 20-year tolling PPA with SRP to purchase and receive all 550 MW of capacity, power and ancillary services from Gila River Unit 2, which includes a three-year option to purchase the unit.

(4) TEP plans to discontinue operations of H. Wilson Sundt Generation Station Units 1 & 2 by the end of 2020.

UNS Electric meets the electricity supply requirements of its retail customers through a mix of its own generation and PPAs. UNS Electric owns and operates several gas and diesel-fuelled generating plants, with a collective electrical generation capacity of 301 MW. In 2018 UNS Electric met a peak demand of 425 MW by utilizing its generation capacity and purchasing power on the wholesale market.

UNS Electric's generating capacity as of December 31, 2018 is set forth in the following table.

Generation Source	Unit No.	Location	Date In Service	Resource Type	Total Capacity (MW)	Operating Agent	UNSE's Share (%)	UNSE's Share (MW)
Black Mountain	1	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Black Mountain	2	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Valencia	1	Nogales, AZ	1989	Gas/Oil	14	UNSE	100.0	14
Valencia	2	Nogales, AZ	1989	Gas/Oil	14	UNSE	100.0	14
Valencia	3	Nogales, AZ	1989	Gas/Oil	14	UNSE	100.0	14
Valencia	4	Nogales, AZ	2006	Gas/Oil	21	UNSE	100.0	21
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	SRP	25.0	137
Utility-Scale Renewables		Various	2011 -2017	Solar	11	UNSE	100.0	11
Total Capacity								**301**

Owned Utility-Scale Renewable Resources

TEP owned 46 MW of photovoltaic solar generation capacity as at December 31, 2018 as set forth in the following table.

Generation Source	Location	Date/Projected Date In Service	In Service Capacity (MW)	Developing Capacity (MW)
Solar				
Fort Huachuca Phase I & II *(1)*	Sierra Vista, AZ	2014-2017	18	—
Springerville	Springerville, AZ	2004-2014	13	—
UASTP Phase I & II *(2)*	Tucson, AZ	2010-2011	5	—
Sundt Areva Solar Thermal	Tucson, AZ	2014	5	—
Solon Prairie Fire *(2)*	Tucson, AZ	2012	4	—
Small PV, Solar (<5MW)	Various	Various	1	—
Wind				
New Mexico Wind Project	Chaves Country, NM	2020	—	150
Total Capacity			**46**	**150**

(1) TEP has a 30-year easement agreement to facilitate operations on behalf of the U.S. Department of the Army.

(2) The University of Arizona Science and Technology Park I & II and Solon Prairie Fire are located on properties held under land easements and leases.

UNS Electric owned 11 MW of photovoltaic solar generation capacity as at December 31, 2018 as set forth in the following table.

Generation Source	Location	Date/Projected Date In Service	Resource Type	In Service Capacity (MW)
Rio Rico	Rio Rico, AZ	2014	Solar	6
Jacobson	Kingman, AZ	2017	Solar	4
La Senita	Kingman, AZ	2011	Solar	1
Total Owned Solar Capacity				**11**

Renewable Power Purchase Agreements

As at December 31, 2018, TEP had renewable PPAs for 159 MW from solar resources, 80 MW from wind resources, and 4 MW associated with the purchase of landfill gas as presented in the following table. The solar PPAs contain options that allow TEP to purchase all or part of the related project at a future date.

Generation Source	Location	Date/Projected Date In Service	In Service Capacity (MW)	Under Development Capacity (MW)
Solar				
Red Horse	Willcox, AZ	2015	41	—
Avalon I	Sahuarita, AZ	2014	28	—
Avra Valley	Marana, AZ	2012	25	—
Picture Rocks	Marana, AZ	2012	20	—
Avalon II	Sahuarita, AZ	2016	17	—
Valencia	Tucson, AZ	2013	10	—
E.On Tech Park	Tucson, AZ	2012	5	—
Gato Montes	Tucson, AZ	2012	5	—
Small PPAs, Solar (<5MW)	Various	Various	8	—
Wilmot Solar	Tucson, AZ	2021	—	100
Wind				
Macho Springs	Deming, NM	2011	50	—
Red Horse Wind	Willcox, AZ	2015	30	—
Borderlands Wind	Catron County, NM	2020	—	99
Biogas				
Sundt - Los Reales *(1)*	Tucson, AZ	1998	4	—
Total Capacity			**243**	**199**

(1) Purchase of landfill gas for use at Sundt

As at December 31, 2018, UNS Electric had renewable PPAs for 55 MW from solar resources and 40 MW from wind resources as set forth in the following table.

Generation Source	Location	Date/Projected Date In Service	Resource Type	In Service Capacity (MW)
GrayHawk Solar	Kingman, AZ	2018	Solar	46
Red Horse Wind	Willcox, AZ	2016	Wind	30
Kingman Wind Farm	Kingman, AZ	2011	Wind	10
Black Mountain Solar	Kingman, AZ	2012	Solar	9
Total PPA Renewable Capacity				**95**

Gas Purchases

TEP and UNS Gas directly manage their gas supply and transportation contracts. The price for gas varies based on market conditions, which include weather, supply balance, economic growth rates, and other factors. TEP and UNS Gas hedge their gas supply prices by entering into fixed-price forward contracts, collars, and financial swaps from time to time, up to ten years in advance, with a view to hedging at least 70-90% of expected monthly energy volumes prior to the beginning of each month.

The following table provides information on the natural gas transportation agreements that deliver natural gas to the generation stations.

Station	Natural Gas Transportation Counterparty	Contract Expiration Date(s)
Gila	Transwestern Pipeline Co./El Paso Natural Gas Company, LLC	2019-2040
	El Paso Natural Gas Company, LLC	
Luna		2022
Sundt	El Paso Natural Gas Company, LLC	2023-2040
DeMoss Petrie	Southwest Gas Corporation	Retail Tariff
North Loop	Southwest Gas Corporation	Retail Tariff

Central Hudson

Central Hudson is a regulated electric and gas T&D utility serving approximately 300,000 electricity customers and 80,000 natural gas customers in portions of New York State's Mid-Hudson River Valley.

Central Hudson serves a territory comprising approximately 6,700 square km in the Hudson Valley. Electric service is available throughout the territory, and natural gas service is provided in and around the cities of Poughkeepsie, Beacon, Newburgh, and Kingston, New York, and in certain outlying and intervening territories.

Central Hudson's electric T&D system consists of more than 15,000 circuit km of line and met a peak demand of 1,114 MW in 2018.

Central Hudson's natural gas system consists of approximately 2,350 km of T&D pipelines and met a peak day demand of 153 TJ in 2018.

Market and Sales

Central Hudson's electricity sales were 5,118 GWh in 2018, compared to 4,891 GWh in 2017. Natural gas sales volumes in 2018 were 24 PJ, compared to 22 PJ in 2017. Revenue was $924 million in 2018, compared to $872 million in 2017.

The following table compares the composition of Central Hudson's 2018 and 2017 revenue, electricity sales and gas volumes by customer class.

	Revenue (%)		GWh Sales (%)		PJ Volumes (%)	
	2018	2017	**2018**	2017	**2018**	2017
Residential	**65.4**	61.5	**42.4**	40.5	**26.9**	25.1
Commercial	**29.2**	27.6	**38.5**	39.0	**35.6**	34.5
Industrial	**3.8**	3.8	**17.9**	19.0	**21.6**	20.5
Other	**0.2**	5.6	**0.5**	0.6	**7.2**	7.6
Sales for Resale	**1.4**	1.5	**0.7**	0.9	**8.7**	12.3
Total	**100.0**	100.0	**100.0**	100.0	**100.0**	100.0

Power Supply

Central Hudson relies on purchased capacity and energy from third-party providers, together with its own minimal generating capacity, to meet the demands of its full-service customers.

Central Hudson is obligated to supply electricity to its retail electric customers. Central Hudson, the staff of the New York State Public Service Commission and others entered into a settlement agreement in 1998 with respect to the auction of fossil-fuel generation plants owned by Central Hudson. Under the settlement agreement, Central Hudson's retail customers may elect to procure electricity from third-party suppliers or may continue to rely on Central Hudson. As part of its requirement to supply customers who continue to rely on Central Hudson for their energy supply, Central Hudson entered into a 10-year revenue sharing agreement with Constellation Energy Group, Inc. in 2011, pursuant to which Central Hudson shares in a portion of the power sales revenue attributable to Unit No. 2 of the Nine Mile Point Nuclear Generating Station.

Central Hudson's PPA to purchase capacity from the Danskammer Generating Facility expired in July 2018 and was not renewed.

Costs of electric and natural gas commodity purchases are recovered from customers, without earning a profit on these costs. Rates are reset monthly based on Central Hudson's actual costs to purchase the electricity and natural gas needed to serve its full-service customers.

FortisBC Energy

FortisBC Energy is the largest distributor of natural gas in British Columbia, serving approximately 1,030,000 residential, commercial and industrial and transportation customers in more than 135 communities. FortisBC Energy provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers.

FortisBC Energy owns and operates approximately 49,500 km of natural gas pipelines and met a peak day demand of 1,353 TJ in 2018.

Market and Sales

FortisBC Energy's natural gas sales volumes were 212 PJ in 2018, compared to 221 PJ in 2017. Revenue was $1,187 million in 2018 compared to $1,198 million in 2017.

The following table compares the composition of FortisBC Energy's 2018 and 2017 revenue and natural gas volumes by customer class.

	Revenue (%)		**PJ Volumes (%)**	
	2018	2017	**2018**	2017
Residential	**57.7**	58.7	**36.3**	37.1
Commercial	**27.7**	28.8	**23.1**	23.5
Industrial	**3.2**	2.1	**2.8**	1.8
Transportation	**11.4**	10.4	**37.8**	37.6
Total	**100.0**	100.0	**100.0**	100.0

Gas Purchase Agreements

To ensure supply of adequate resources for reliable natural gas deliveries to its customers, FortisBC Energy purchases natural gas supply from counterparties, including producers, aggregators and marketers. FortisBC Energy contracts for approximately 154 PJ of baseload and seasonal supply, of which the majority is sourced in northeast British Columbia and transported on Westcoast Energy Inc.'s T-South pipeline system. The remainder is sourced in Alberta and transported on TransCanada's pipeline transportation system.

FortisBC Energy procures and delivers natural gas directly to core market customers. Transportation customers are responsible to procure and deliver their own natural gas to the FortisBC Energy system and FortisBC Energy then delivers the gas to the operating premises of these customers. FortisBC Energy contracts for transportation capacity on third-party pipelines, such as the T-South pipeline and the TransCanada pipeline, to transport gas supply from various market hubs to FortisBC Energy's system. These third-party pipelines are regulated by the National Energy Board. FortisBC Energy pays both fixed and variable charges for the use of transportation capacity on these pipelines, which are recovered through rates paid by FortisBC Energy's core market customers. FortisBC Energy contracts for firm transportation capacity to ensure it is able to meet its obligation to supply customers within its broad operating region under all reasonable demand scenarios.

Gas Storage and Peak Shaving Arrangements

FortisBC Energy incorporates peak shaving and gas storage facilities into its portfolio to: (i) supplement contracted baseload and seasonal gas supply in the winter months, while injecting excess baseload supply to refill storage in the summer months; (ii) mitigate the risk of supply shortages during cooler weather and peak day; (iii) manage the cost of gas during the winter months; and (iv) balance daily supply and demand on the distribution system during periods of peak use that occur during the winter months.

FortisBC Energy holds approximately 35 PJs of total storage capacity. FortisBC Energy owns Tilbury and Mount Hayes liquefied natural gas peak shaving facilities, which provide on-system storage capacity and deliverability. FortisBC Energy also contracts for underground storage capacity and deliverability from third parties in northeast British Columbia, Alberta and the Pacific Northwest of the United States. On a combined basis, FortisBC Energy's Tilbury and Mount Hayes facilities, the contracted storage facilities, and other peaking arrangements can deliver up to 0.73 PJs per day of supply to FortisBC Energy on the coldest days of the heating season. The heating season typically occurs from December to February.

Mitigation Activities

FortisBC Energy engages in off-system sales activities that allow for the recovery or mitigation of costs of any unutilized supply and/or pipeline and storage capacity that is available once customers' daily load requirements are met.

Under the GSMIP revenue sharing model, which is approved by the BCUC, FortisBC Energy can earn an incentive payment for mitigation activities. Historically, FortisBC Energy has earned approximately $1.7 million annually through GSMIP, while the remaining savings are credited back to customers through reduced rates. Subject to the BCUC's approval, FortisBC Energy earned an incentive payment of approximately $2.6 million for the gas contract year ended October 31, 2018.

The current GSMIP program was approved by the BCUC following a comprehensive review in 2011. The BCUC has approved extensions of the program through October 31, 2019.

Price-Risk Management Plan

FortisBC Energy engages in price-risk management activities to mitigate the impact on customer rates of fluctuations in natural gas prices. These activities include: (i) physical gas purchasing and storage strategies; (ii) current quarterly commodity rate-setting and a deferral account mechanism; and (iii) the use of derivative instruments, which were implemented pursuant to a price-risk management plan approved by the BCUC, as discussed below.

On June 17, 2016, the BCUC approved FortisBC Energy's 2015 Price-Risk Management Application which included FortisBC Energy's request to implement a medium-term (maximum three years out) hedging program including specific market price targets and commodity rate-setting enhancements. During 2018 the market price targets and maximum volume limits were reached and, therefore, the price risk strategies were implemented.

On June 13, 2017, FortisBC Energy filed a request to extend and amend the terms of the previously approved price-risk management plan. The BCUC directed FortisBC Energy to amend the 2017 application or file a revised application to address questions regarding the price risk management objectives and strategies. FortisBC Energy filed a revised 2018 Price Risk Management Application on January 5, 2018, which is being reviewed by the BCUC.

Unbundling

A Customer Choice program at FortisBC Energy allows eligible commercial and residential customers to buy their natural gas commodity supply from FortisBC Energy or from third-party marketers. FortisBC Energy continues to provide the delivery service of the natural gas to all its customers. For the year ended December 31, 2018, approximately 4% of eligible commercial customers and 3% of eligible residential customers purchased their commodity supply from alternate providers.

FortisAlberta

FortisAlberta is a regulated electricity distribution utility operating in Alberta. Its business is the ownership and operation of regulated electricity distribution facilities that distribute electricity, generated by other market participants, from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct retail sale of electricity. FortisAlberta operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 89,000 circuit km of distribution lines. Many of FortisAlberta's customers are located in rural and suburban areas around and between the cities of Edmonton and Calgary. FortisAlberta's distribution network serves approximately 564,000 customers, comprised of residential, commercial, farm, oil and gas and industrial consumers, and met a peak demand of 2,743 MW in 2018.

Market and Sales

FortisAlberta's annual energy deliveries were 17,154 GWh in 2018 compared to 17,018 GWh in 2017. Revenue was $579 million in 2018 compared to $600 million in 2017.

The following table compares the composition of FortisAlberta's 2018 and 2017 revenue and energy deliveries by customer class.

	Revenue (%)		**GWh Deliveries (%)** *(1)*	
	2018	2017	**2018**	2017
Residential	**30.9**	30.7	**18.5**	18.1
Large commercial, industrial and oil field	**21.2**	20.8	**59.0**	59.6
Farms	**12.3**	13.0	**8.6**	8.5
Small commercial	**12.2**	12.2	**8.4**	8.1
Small oil field	**8.4**	8.7	**5.2**	5.3
Other *(2)*	**15.0**	14.6	**0.3**	0.4
Total	**100.0**	100.0	**100.0**	100.0

(1) GWh percentages exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries were 7,024 GWh in 2018 and 6,691 GWh in 2017, based on an interim settlement that is expected to be finalized in May 2019, and consisted primarily of energy deliveries to large-scale industrial customers directly connected to the transmission grid.

(2) Includes revenue from sources other than the delivery of energy, including revenues resulting from street-lighting services, rate riders, deferrals and adjustments

Franchise Agreements

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

FortisAlberta holds franchise agreements with 160 municipalities within its service territories. The franchise agreements include 10-year terms with an option to renew for up to two subsequent five-year terms. Over 99% of FortisAlberta's franchise agreements are on the 2012 franchise agreement template, pursuant to which the initial terms will not expire until the end of 2022 and beyond.

FortisBC Electric

FortisBC Electric is an integrated regulated electric utility that owns hydroelectric generating plants, high voltage transmission lines, and a large network of distribution assets, all of which are located in the southern interior of British Columbia. FortisBC Electric serves approximately 176,000 customers and met a peak demand of 663 MW in 2018. FortisBC Electric's T&D assets include approximately 7,300 circuit km of T&D lines.

FortisBC Electric is also responsible for operation, maintenance and management services at the 493-MW Waneta hydroelectric generating facility owned by BC Hydro; the 335-MW Waneta Expansion, owned by the Waneta Partnership between Fortis, CBT and CPC; and the 149-MW Brilliant hydroelectric plant, the 120-MW Brilliant hydroelectric expansion plant and the 185-MW Arrow Lakes generating station, all owned by CBT and CPC.

Market and Sales

FortisBC Electric has a diverse customer base comprised of residential, commercial, industrial and municipal wholesale, and other industrial customers. Electricity sales were 3,250 GWh in 2018, compared to 3,305 GWh in 2017. Revenue was $408 million in 2018, compared to $398 million in 2017.

The following table compares the composition of FortisBC Electric's 2018 and 2017 revenue and electricity sales by customer class.

	Revenue (%)		**GWh Sales (%)**	
	2018	2017	**2018**	2017
Residential	**51.1**	51.0	**40.8**	41.5
Commercial	**27.1**	26.8	**30.1**	29.4
Wholesale	**13.3**	13.7	**17.6**	17.9
Industrial	**8.5**	8.5	**11.5**	11.2
Total	**100.0**	100.0	**100.0**	100.0

Generation and Power Supply

FortisBC Electric meets the electricity supply requirements of its customers through a mix of its own generation and PPAs. FortisBC Electric owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 225 MW, which provide approximately 45% of its energy needs and 30% of its peak capacity needs. FortisBC Electric meets the balance of its requirements through a portfolio of long-term and short-term PPAs.

FortisBC Electric's four hydroelectric generating facilities are governed by the multi-party CPA that enables the five separate owners of nine major hydroelectric generating plants, with a combined capacity of approximately 1,900 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their generating plants.

The following table lists the plants and their respective capacity and owner.

Plant	**Capacity (MW)**	**Owners**
Canal Plant	580	BC Hydro
Waneta Dam	493	BC Hydro
Waneta Expansion	335	Waneta Partnership
Kootenay River System	225	FortisBC Electric
Brilliant Dam	149	Brilliant Power Corporation
Brilliant Expansion	120	Brilliant Expansion Power Corporation
Total	**1,902**	

Brilliant Power Corporation, Brilliant Expansion Power Corporation, Teck Metals Ltd., Waneta Partnership and FortisBC Electric are collectively defined in the CPA as the entitlement parties. The CPA enables BC Hydro and the entitlement parties to generate more power from their respective generating plants than they could if they operated independently through coordinated use of water flows, subject to the 1961 *Columbia River Treaty* between Canada and the United States, and coordinated operation of storage reservoirs and generating plants. Under the CPA, BC Hydro takes into its system all power actually generated by the plants listed in the table above. In exchange for permitting BC Hydro to determine the output of these facilities, each of the entitlement parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is based on 50-year historical water flows and the plants' generating capabilities. The entitlement parties receive their defined entitlements irrespective of actual water flows to the entitlement parties' generating plants. BC Hydro enjoys the benefits of the additional power generated through coordinated operation and optimal use of water flows. The entitlement parties benefit by knowing years in advance the amount of power that they will receive from their generating plants and, therefore, do not face hydrology variability in generation supply planning. However, FortisBC Electric retains rights to its original water licenses and flows in perpetuity. Should the CPA be terminated, the output of FortisBC Electric's Kootenay River system plants would, with the water and storage authorized under its existing licences and on a long-term average, be approximately the same power output as FortisBC Electric receives under the CPA. The CPA does not affect FortisBC Electric's ownership of its physical generation assets. The CPA continues in force until terminated by any of the parties by giving no less than five years' notice at any time on or after December 31, 2030.

FortisBC Electric's remaining electricity supply is acquired through short and long-term PPAs with a number of counterparties, including electricity produced by the Waneta Expansion, a hydroelectric project owned by the Waneta Partnership, which is 51% owned by Fortis and 49% owned by a subsidiary of each of CBT and CPC. During 2018, FortisBC Electric purchased capacity and energy from the market to meet its peak energy requirements and optimize its overall power supply portfolio. Spot market and contracted purchases provided approximately 15% of FortisBC Electric's energy supply requirements in 2018. FortisBC Electric's PPAs and market purchases have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Electric's electricity rates.

Other Electric

Other Electric is comprised of utilities in eastern Canada and the Caribbean as follows: Newfoundland Power; Maritime Electric; FortisOntario; a 39% equity investment in Wataynikaneyap Partnership; an approximate 60% controlling interest in Caribbean Utilities; FortisTCI; and a 33% equity investment in Belize Electricity.

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on PEI. FortisOntario provides integrated electric utility service through its three regulated operating utilities in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario.

Caribbean Utilities is an integrated regulated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. FortisTCI is an integrated regulated electric utility on the Turks and Caicos Islands. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize. The results of Belize Electricity are not included in the description of this segment.

Wataynikaneyap Partnership is partnership between 24 First Nations communities and Fortis with a mandate of connecting remote First Nations Communities to the electricity grid in Ontario through the development of new transmission lines. In March 2018 the project reached a significant milestone with the formal announcement of a funding framework among Wataynikaneyap Partnership, the Government of Canada and the Government of Ontario. In January 2019 Fortis reduced its equity investment in Wataynikaneyap Partnership from 49% to 39% to facilitate the inclusion of two additional First Nations communities into the partnership.

The following table sets out the customers, installed generating capacity, peak demand and kilometers of T&D lines for the segment.

	Customers	Peak Demand (MW)	T&D Lines (km) *(1)*	Generating Capacity (MW)	Resource Type(s)
Newfoundland Power	268,000	1,362	12,600	139	Hydroelectric, Gas, Diesel
Maritime Electric	81,000	280	6,100	145	Thermal, Diesel
FortisOntario *(2)*	66,000	257	3,500	5	Natural Gas Cogeneration
Caribbean Utilities *(3)*	30,000	94	750	161	Diesel
FortisTCI	15,000	41	650	91	Diesel
Total	**460,000**	**2,034**	**23,600**	**541**	

(1) Circuit km
(2) FortisOntario also owns a 10% interest in certain regional electric distribution companies serving approximately 40,000 customers.
(3) Includes 24 km of high-voltage submarine cable

Market and Sales

Electricity sales attributable to Other Electric were 9,292 GWh in 2018, compared to 9,196 GWh in 2017. Revenue was $1,412 million in 2018, compared to $1,363 million in 2017.

The following table compares the composition of revenue and electricity sales by customer class for Other Electric in 2018 and 2017.

	Revenue (%)		GWh Sales (%)	
	2018	2017	**2018**	2017
Residential	**54.3**	54.4	**55.6**	55.8
Commercial and Industrial	**43.5**	42.6	**44.3**	43.9
Other *(1)*	**2.2**	3.0	**0.1**	0.3
Total	**100.0**	100.0	**100.0**	100.0

(1) Includes revenue from sources other than from the sale of electricity

Power Supply

Newfoundland Power

Approximately 93% of Newfoundland Power's energy requirements are purchased from NL Hydro with the remaining 7% generated by Newfoundland Power generating facilities. The principal terms of the supply arrangements with NL Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

NL Hydro charges Newfoundland Power for purchased power and includes charges for both demand and energy purchased. The demand charge is based on applying a rate to the peak-billing demand for the most recent winter season. The energy charge is a two-block charge with a higher second-block charge set to reflect NL Hydro's marginal cost of generating electricity.

Future changes in supply costs, including costs associated with the Nalcor Energy Muskrat Falls hydroelectric generation development and associated transmission assets, may increase electricity prices in a manner that adversely affects Newfoundland Power's sales. In 2017 Nalcor Energy indicated that the cost of the Muskrat Falls project is projected to reach $12.7 billion. A public inquiry into the Muskrat Falls project, commissioned by the Government of Newfoundland and Labrador, began in 2018 and is scheduled to conclude by December 31, 2019. The Government of Newfoundland and Labrador has also requested the PUB to examine options to mitigate the impact of the Muskrat Falls project on electricity prices. This process by the PUB is ongoing.

Newfoundland Power experienced losses of electricity supply from NL Hydro in January 2013 and January 2014, which prevented Newfoundland Power from meeting its customers' requirements. The PUB conducted an inquiry and hearing into these system supply issues and power interruptions. The results indicated that significant concerns remain in relation to the adequacy and reliability of supply from NL Hydro.

Maritime Electric

Maritime Electric purchases approximately 78% of the electricity required to meet its customers' needs from NB Power, a New Brunswick Crown corporation. The balance is met through the purchase of wind energy produced on PEI by facilities owned by the PEI Energy Corporation and from company-owned on-Island generation, used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric has contracts with NB Power for the purchase of either energy or capacity: (i) covering the periods March 1, 2011 to February 28, 2019 and March 1, 2019 to February 29, 2024; and (ii) a transmission capacity contract allowing Maritime Electric to reserve 30 MW of capacity to PEI expiring November 2032.

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 and as part of its entitlement is required to pay its share of the capital and operating costs of the unit.

FortisOntario

The power requirements of FortisOntario's service territories are met through various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from IESO and purchases approximately 80% of energy requirements for Gananoque through monthly energy purchases from Hydro One Networks Inc. and 20% from the five hydroelectric generating plants of EO Generation LP. Algoma Power purchases 100% of its energy from IESO.

Under the Standard Supply Code of the Ontario Energy Board, Canadian Niagara Power and Algoma Power are obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Cornwall Electric purchases substantially all of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts, the first providing approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time, and the second contract providing 100 MW of capacity and energy and a minimum of 300 GWh of energy per year. Both contracts expire in December 2019. In 2016 Cornwall Electric successfully negotiated a new contract that commences January 2020 and expires December 2030. The new contract will provide a minimum of 537 GWh of energy per year and up to 145 MW of capacity at any one time.

Caribbean Utilities

Caribbean Utilities relies upon in-house diesel-powered generation to produce electricity for its customers. Caribbean Utilities is party to primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing 60% and 40%, respectively, of its diesel fuel requirements for its diesel-powered generating plant. Caribbean Utilities executed two 24-month fuel supply contracts in June 2018 with the option to renew for two additional terms of 18 months at the end of each term.

FortisTCI

FortisTCI relies upon in-house diesel-powered generation to produce electricity for its customers. In 2018 FortisTCI commissioned its fourth 8-MW Wartsila 30V32 engine. In addition, FortisTCI installed and commissioned two photovoltaic systems under its Utility Owned Renewable Energy Program with a total aggregate size of 250 kW (direct current).

FortisTCI has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 14 million imperial gallons per annum.

Non-Regulated

Energy Infrastructure

The Corporation's Energy Infrastructure segment is primarily comprised of long-term contracted generation assets in British Columbia and Belize, and a gas storage facility in British Columbia (Aitken Creek). Generation assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion. All of the output of the Waneta Expansion is sold to BC Hydro and FortisBC Electric under 40-year contracts. As described earlier, in January 2019 the Corporation entered into a definitive agreement to sell its interest in the Waneta Expansion. FortisBC Electric operates and maintains the Waneta Expansion and will continue to operate the facility following the sale.

Generation assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW held through the Corporation's subsidiary BECOL. All of the output of these facilities is sold to Belize Electricity under 50-year PPAs expiring in 2055 and 2060.

ACGS, acquired by Fortis in April 2016, owns 93.8% of Aitken Creek, the only underground natural gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet. ACGS contracts with third parties for both lease and park transactions and also holds its own proprietary capacity.

Market and Sales

Energy sales were 853 GWh in 2018, compared to 889 GWh in 2017. Revenue was $184 million in 2018, compared to $226 million in 2017.

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 FHI.

HUMAN RESOURCES

As of December 31, 2018, Fortis and its subsidiaries had 8,800 employees, with 52% in Canada, 43% in the U.S. and 5% in other countries. The following table provides the breakdown of employees by reportable segment.

	Employees	Participation in a Collective Agreement	Union(s)	Collective Agreement(s) Expiry Date(s)
Regulated Utilities				
ITC	692	None	—	—
UNS Energy	2,049	51%	International Brotherhood of Electrical Workers	June 2019 – July 2022
Central Hudson	1,014	59%	International Brotherhood of Electrical Workers	March 2021 – April 2022
FortisBC Energy *(1)*	1,846	66%	International Brotherhood of Electrical Workers, Canadian Office and Professional Employees Union	March 2019 – June 2023
FortisAlberta	1,110	79%	United Utility Workers' Association of Canada	December 2020
FortisBC Electric	525	70%	International Brotherhood of Electrical Workers, Canadian Office and Professional Employees Union	December 2019 – March 2022
Other Electric *(2)*	1,440	40%	International Brotherhood of Electrical Workers, Canadian Union of Public Employees, Power Workers' Union	September 2017 *(3)* – December 2019
Non-Regulated				
Energy Infrastructure *(4)*	65	None	—	—
Corporate and Other *(5)*	59	None	—	—
Total	**8,800**	**53%**		

(1) Includes employees at FHI.

(2) Includes employees at Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and FortisTCI. Excludes Belize Electricity.

(3) The two collective agreements between Newfoundland Power and IBEW Local 1620 covering 337 Newfoundland Power employees expired on September 30, 2017. Collective agreement negotiations began in the fourth quarter of 2017. Conciliation proceedings occurred in the second quarter of 2018 and no tentative agreements have been reached to date. An application filed by Newfoundland Power to establish essential employees in the event of a labour dispute is under review by the PUB.

(4) Includes employees at Aitken Creek (staffed by FortisBC Midstream Inc.), BECOL and FortisBC Alternative Energy Services Inc. The Waneta Expansion is staffed by employees of FortisBC Electric.

(5) Employees at Fortis Inc.

The Corporation's culture is built on safety, diversity and integrity. Fortis employees are driven to make good decisions, work hard and work safely. Fortis and its utilities respect their employees' freedom to associate and strive to maintain positive and constructive relationships with labour associations and unions. Approximately 53% of the Corporation's employees are covered by a collective bargaining agreement.

The Corporation's subsidiaries are required to develop and retain skilled workforces for their operations. Many of the employees of the Corporation's utilities possess specialized skills and training and Fortis must compete in the marketplace for these workers. The Corporation's significant consolidated capital expenditure program may present challenges to ensure its utilities have the qualified workforce necessary to complete the capital work initiatives.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that involve a claim for damages exceeding 10% of the Corporation's current assets in respect of which the Corporation is or was a party, or in respect of which any of the Corporation's property is or was the subject during the year ended December 31, 2018, nor are there any such proceedings known to the Corporation to be contemplated.

Information related to the Corporation's legal proceedings can be found in Note 30 of the 2018 Audited Consolidated Financial Statements, which are incorporated by reference in this AIF and available on SEDAR.

The Corporation's utilities primarily operate under a cost of service regulation, in combination with performance-based rate-setting mechanisms in certain jurisdictions, and are regulated by the regulatory body in their respective operating jurisdiction. There have not been any: (a) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2018; (b) other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; or (c) settlement agreements entered into by the Corporation before a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2018.

For information with respect to the nature of regulation and material regulatory decisions and applications associated with each of the Corporation's utilities, refer to the "Regulatory Highlights" section of the MD&A and to Notes 2 and 9 of the Corporation's 2018 Audited Consolidated Financial Statements, each of which are incorporated by reference in this AIF and available on SEDAR.

RISK FACTORS

For information with respect to the Corporation's business risks, refer to the "Business Risk Management" section of the MD&A, which is incorporated by reference in this AIF and available on SEDAR.

CORPORATE SOCIAL RESPONSIBILITY

Fortis is committed to operating in an environmentally and socially responsible manner. Having strong, reliable infrastructure and adapting its systems to deliver energy more efficiently and to facilitate cleaner energy on the grid are ways the Corporation helps create a lower-carbon economy and deliver on customer expectations.

Social and Environmental Policies

The Corporation and its utilities each have a range of social and environmental policies, programs and practices. Fortis has a Code of Business Conduct and Ethics which sets out the Corporation's standards for the ethical conduct of its business, applicable to all of its directors, officers and employees, and to the extent feasible also to consultants, contractors and representatives of Fortis and its subsidiaries. To ensure implementation, Fortis and its utilities hold regular employee training and require all employees to sign, understand and deliver on the Code of Business Conduct and Ethics.

The Code of Business Conduct and Ethics is supported by other policies that outline the behaviour expected by management and employees including the Anti-Corruption Policy and Respectful Workplace Policy. Defined whistleblower and complaint management processes are in place at all Fortis operating subsidiaries to support reporting behaviour not aligned with the Code of Business Conduct and Ethics and other workplace policies.

The Corporation's Diversity Policy describes the principles and objectives for diversity among the Board and the Corporation's executive leadership, including a commitment to maintaining a Board where at least one-third of its independent directors are represented by each gender - a level that Fortis currently exceeds. For further information on the Corporation's Diversity Policy, refer to the Corporation's Management Information Circular dated March 16, 2018, which is available on SEDAR.

Each of the operating subsidiaries are also responsible for implementing additional policies, programs and practices that take into account the jurisdiction and operations of the subsidiary. Social and environmental policies in place at the Corporation's utilities include, among others: Health, Safety, and Environmental Policies; Diversity Policies; Equal Opportunity Policies; Respectful Workplace, Workplace Harassment and Violence Policies; Disability Non-Discrimination Policies; and Accommodation Policies.

Environmental, Sustainability and Regulatory Oversight

Fortis believes that responsible environmental and sustainability management is good for the planet, business and its customers. The Corporation is focused on operating its energy networks in a sustainable manner, helping its customers in their transition to a lower-carbon economy and achieving its goal of delivering safe, reliable and efficient energy over the long term. The Corporation's environmental statement sets out its commitment to comply with all applicable laws and regulations relating to the protection of the environment, regularly conduct monitoring and audits of environmental management systems and seek feasible, cost-effective opportunities to decrease GHG emissions and increase renewable energy sources.

Oversight of sustainability is integrated into each senior level of responsibility at Fortis. The Board is responsible for risk management oversight and ensuring that business is conducted to meet high standards of environmental and social responsibility. The Governance and Nominating Committee of the Board is responsible for overseeing governance structure and practices, including reviewing programs designed to promote corporate citizenship and environmental and social responsibility. The Executive Vice President, Sustainability and Chief Human Resource Officer is responsible for enterprise-wide sustainability and stewardship. Sustainability performance impacts how Fortis executives are compensated. Performance in the core areas of system reliability and safety is linked to incentive compensation for all Fortis executives. In addition, local management teams and boards of directors at each of the Corporation's utilities are responsible for operational aspects of sustainability.

Fortis is primarily an energy delivery company with 93% of its assets dedicated to energy delivery. This naturally limits its impact on the environment when compared with energy generation intensive businesses. The Corporation's GHG emissions come primarily from its generation assets, including fossil fuel-based generation representing 5% of the Corporation's total assets. TEP is the Corporation's primary producer of fossil fuel-based generation and is taking significant steps to reduce coal-fired generation and resulting carbon emissions. TEP is targeting to serve 30% of its retail load from renewable generation by 2030, doubling the State of Arizona's 2025 goal. To achieve this goal, TEP anticipates bringing 450 MW of renewable resources on line by 2021, including 100 MW of solar with a 30 MW battery and up to 350 MW of wind. TEP is also planning a 36% (508 MW) reduction in coal-fired generation by 2022 through plant retirements. Fortis is focused on decreasing its carbon intensity and its utilities achieved a 63% decrease during the period 2015 to 2017.

Fortis and its subsidiaries share a commitment to the environment, health and safety in their operations. The Fortis Sustainability Working Group, comprised of key leaders from across the Fortis group of utilities, is responsible for the Corporation's sustainability strategy and directing reporting practices and enables communication and sharing of information among the Corporation's utilities on sustainability performance, issues and opportunities. In addition, each operating subsidiary has extensive environmental compliance programs, most having adopted the ISO 14001 standard. Each operating subsidiary regularly reviews its environmental management systems and protocols, strives for continual performance improvement and regularly sets and reviews environmental objectives, targets and programs. The Fortis Operating Group consists of senior operational executives from all utilities and meets regularly to share best practices and identify opportunities for collaboration on a range of topics including environment, health and safety.

As part of the regulatory process, each operating subsidiary continually engages with stakeholders including community groups, regulators and customers, to discuss the environmental impact of investment opportunities to deliver safe, reliable, efficient energy to customers in their service territories. The Corporation and its subsidiaries are subject to various federal, provincial, state and municipal laws, regulations and guidelines relating to the protection of the environment. Compliance with environmental laws, regulations and guidelines involve significant operating and capital costs. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are generally eligible for recovery in customer rates. There is no assurance, however, that all such costs will be recovered or that continued recovery in customer rates will be permitted.

Environmental Contingencies

Mine Reclamation at Generation Facilities Not Operated by TEP. TEP pays ongoing reclamation costs related to three coal mines that supply generation facilities in which TEP has an ownership interest but does not operate. TEP's share of the reclamation costs is expected to be US$66 million upon expiry of the coal agreements, which expire between 2019 and 2031. The mine reclamation liability recognized as at December 31, 2018 was $49 million (US$36 million) and represents the present value of the estimated future liability.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms. TEP does not believe that recognition of its final reclamation obligations will be material in any single year because recognition will occur over the remaining terms of its coal supply agreements. TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset.

Former Manufactured Gas Plant Facilities. Environmental regulations require Central Hudson to investigate sites at which Central Hudson or its predecessors once owned and/or operated manufactured gas plants and, if necessary, remediate these sites. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2018, an obligation of $64 million (US$47 million) was recognized. Central Hudson has notified its insurers and intends to seek reimbursement where insurance coverage exists. Further, as authorized by the New York Public Service Commission, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for manufactured gas plant site investigation and remediation and the associated rate allowances.

CAPITAL STRUCTURE AND DIVIDENDS

Description of Capital Structure

The authorized share capital of the Corporation consists of an unlimited number of common shares without nominal or par value, an unlimited number of first preference shares without nominal or par value, and an unlimited number of second preference shares without nominal or par value.

As at February 14, 2019, the Corporation had issued and outstanding 428.6 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.

For a summary of the terms and conditions of the Corporation's authorized securities, and trading information for the Corporation's publicly listed securities, refer to Exhibit "A" and Exhibit "B" of this AIF.

Dividends and Distributions

The declaration and payment of dividends on the Corporation's common shares and first preference shares are at the discretion of the Board. Dividends on the common shares are typically paid quarterly, on the first day of March, June, September and December of each year. Dividends on the Corporation's First Preference Shares, Series F, G, H, I, J, K and M are typically paid quarterly.

In October 2018 Fortis increased its quarterly dividend per common share 5.9% to $0.45 per share, or $1.80 on an annualized basis. In November 2018 the Board declared a first quarter 2019 dividend on the common shares of $0.45 per share and on the First Preference Shares, Series F, G, H, I, J, K and M in accordance with the applicable prescribed rate. The first quarter dividends on the common shares and the First Preference Shares, Series F, G, H, I, J, K and M are to be paid on March 1, 2019 to holders of record as of February 15, 2019.

Fortis is targeting average annual dividend growth of 6% through 2023. 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 its five-year capital expenditure program, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence.

The following table summarizes the cash dividends declared per share for each of the Corporation's class of shares for the past three years.

	2018	2017	2016
Common Shares	1.75	1.65	1.55
First Preference Shares, Series E *(1)*	—	—	0.6126
First Preference Shares, Series F *(2)*	1.2250	1.2250	1.2250
First Preference Shares, Series G *(3)*	1.0345	0.9708	0.9708
First Preference Shares, Series H *(4)*	0.6250	0.6250	0.6250
First Preference Shares, Series I *(5)*	0.7116	0.5262	0.4874
First Preference Shares, Series J *(2)*	1.1875	1.1875	1.1875
First Preference Shares, Series K *(6)*	1.0000	1.0000	1.0000
First Preference Shares, Series M *(7)*	1.0250	1.0250	1.0250

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

(2) The dividend rate on the First Preference Shares, Series F and First Preference Shares, Series J are fixed and do not reset.

(3) The annual fixed dividend per share for the First Preference Shares, Series G was reset from $0.9708 to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.

(4) 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.

(5) The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate will reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

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

(7) The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years.

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preference shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $200 million Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

The Corporation has a $1.3 billion unsecured committed revolving corporate credit facility, maturing in July 2023, that is available for general corporate purposes. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 65% at any time.

As at December 31, 2018 and 2017, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

Credit Ratings

Securities issued by Fortis and its utilities, that are currently rated, are rated by one or more credit rating agencies, namely DBRS, Fitch, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its utilities are reviewed by the agencies on an ongoing basis. Credit and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's debt credit ratings as at February 14, 2019.

Company/Security	DBRS	S&P	Moody's
Fortis - Senior Unsecured Debt (1)	BBB (high), Stable	BBB+, Negative	Baa3, Stable
Caribbean Utilities - Senior Unsecured Debt (1)	A (low), Stable	A-, Negative	—
Central Hudson - Senior Unsecured Debt (2) (3)	—	A-, Stable	A2, Negative
FortisBC Energy			
Senior Unsecured Debt	A, Stable	—	A3, Stable
Commercial Paper	R-1 (low), Stable	—	—
FortisAlberta - Senior Unsecured Debt (1)	A (low), Stable	A-, Negative	Baa1, Stable
FortisBC Electric			
Senior Secured Debt	A (low), Stable	—	—
Senior Unsecured Debt	A (low), Stable	—	Baa1, Stable
ITC Holdings (1)			
Senior Unsecured Debt	—	A-, Negative	Baa2, Stable
Commercial Paper	—	A-2, Negative	Prime-2, Stable
ITC Great Plains - First Mortgage Bonds (1)	—	A, Negative	A1, Stable
ITC Midwest - First Mortgage Bonds (1)	—	A, Negative	A1, Stable
ITCTransmission - First Mortgage Bonds (1)	—	A, Negative	A1, Stable
Maritime Electric - Senior Secured Debt	—	A, Stable	—
METC - Senior Secured Debt (1)	—	A, Negative	A1, Stable
Newfoundland Power - First Mortgage Bonds	A, Stable	—	A2, Stable
TEP (1)			
Senior Unsecured Debt	—	A-, Negative	A3, Stable
Senior Unsecured Bank Credit Facility			
UNS Electric			
Senior Unsecured Debt	—	—	A3, Stable
Senior Unsecured Bank Credit Facility	—	—	A3, Stable
UNS Gas - Senior Unsecured Debt	—	—	A3, Stable
UNS Energy - Senior Unsecured Bank Credit Facility	—	—	Baa1, Stable

(1) *In March 2018 S&P affirmed the Corporation's credit ratings and revised its outlook from stable to negative due to modest temporary weakening of financial measures as a result of U.S. tax reform, which reduces cash flow at the Corporation's U.S. regulated utilities. As a result of the Corporation's revised outlook, S&P also revised its outlook on Caribbean Utilities, FortisAlberta, ITC Holdings, ITC Great Plains, ITC Midwest, ITCTransmission, METC and TEP.*

(2) *In July 2018 Moody's revised its outlook on Central Hudson from stable to negative due to the impacts of U.S. Tax Reform and higher capital expenditures.*

(3) *Central Hudson's senior unsecured debt is also rated by Fitch at 'A-'.*

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (i) its long-term debt ratings are meant to give an indication of the risk that the borrower will not fulfill its obligations in a timely manner with respect to both interest and principal commitments; (ii) its ratings do not take factors such as pricing or market risk into consideration and are expected to be used by purchasers as one part of their investment decision; and (iii) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities rated in the BBB category are considered to have long-term debt of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category.

S&P's long-term debt ratings are on a ratings scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. Such modifiers are not added to ratings below CCC. S&P states that its credit ratings are current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories. Debt instruments rated BBB exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the issuer to meet its financial commitment on the obligation.

Moody's long-term debt ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities. In addition, Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa to Caa to indicate relative standing within such classification. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking in its generic rating category and the modifier 3 indicates that the security ranks in the lower end of its generic rating category. Moody's states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that such ratings reflect both the likelihood of default and any financial loss suffered in the event of default. According to Moody's, a rating of Baa is the fourth highest of nine major categories and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics. Debt instruments rated A are considered upper-medium grade and are subject to low credit risk.

Moody's short-term debt ratings are on a rating scale that includes four designations, all of which are judged to be investment grade. From highest to lowest relative repayment ability of rated issuers, such designations are Prime-1, Prime-2, Prime-3 and Not Prime. Issuers with a Not Prime rating do not fall within any of the Prime rating categories. According to Moody's, a rating of Prime-2 means that an issuer has a strong ability to repay short-term debt obligations.

Fitch's long-term debt ratings are on a rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities. Fitch uses '+' or '-' designations to indicate the relative status of securities within a particular rating category. Such modifiers are not added to the AAA rating or to ratings below B. Fitch states that its credit ratings provide an opinion on the relative ability of an entity to meet financial commitments, such as interest, preferred dividends, repayment of principal, insurance claims or counterparty obligations. Fitch's credit ratings do not directly address any risk other than credit risk. The rating of A denotes expectation of low default risk, with strong capacity for payment of financial commitments. A rating of BBB denotes current expectations of low default risk, with adequate capacity for the payment of financial commitments.

The Corporation and/or each of its currently rated utilities pay DBRS, Fitch, S&P and/or Moody's an annual monitoring fee and a one-time fee in connection with each rated issuance. In 2018 Fortis also paid fees to DBRS in respect of advisory services provided in connection with potential asset dispositions.

DIRECTORS AND OFFICERS

The Board has governance guidelines that cover various items, including director tenure. The governance guidelines provide that Directors of the Corporation are to be elected for a term of one year and, except in exceptional circumstances determined by the Board, are eligible for re-election until the annual meeting of shareholders following the date they turn 72 or until they have served on the Board for 12 years, whichever is earlier.

The following table sets out the name, province or state, and country of residence of each of the Directors of the Corporation and their principal occupations during the five preceding years. Each Director's current term expires at the next annual meeting of shareholders.

Name, Residence, Principal Occupation Within Five Preceding Years	Director Since	Committees *(1)*		
		AC	GN	HR
DOUGLAS J. HAUGHEY *(Chair),* Alberta, Canada Corporate Director	2009	I	I	I
TRACEY C. BALL, British Columbia, Canada Corporate Director. Executive Vice President and Chief Financial Officer of Canadian Western Bank Group from 2006 to 2014.	2014	**C**	I	
PIERRE J. BLOUIN, Quebec, Canada Corporate Director. Chief Executive Officer of Manitoba Telecom Services, Inc. from 2005 to 2014.	2015		I	I
PAUL J. BONAVIA, Texas, USA Corporate Director. Executive Board Chair of UNS Energy from May 2014 to August 2014 and Chairman, President and Chief Executive Officer from 2009 to May 2014.	2018		I	I
LAWRENCE T. BORGARD, Florida, USA Corporate Director. President and Chief Operating Officer of Integrys Energy Group from 2007 to 2015.	2017	I		I
MAURA J. CLARK, New York, USA Corporate Director. President of Direct Energy Business at Direct Energy, a subsidiary of Centrica plc, from 2007 to 2014.	2015	I	I	
MARGARITA K. DILLEY, District of Columbia, USA Corporate Director	2016	I		I
JULIE A. DOBSON, Maryland, USA Corporate Director	2018	I	I	
IDA J. GOODREAU, British Columbia, Canada Corporate Director	2009		**C**	**I**
BARRY V. PERRY, Newfoundland and Labrador, Canada President and Chief Executive Officer of the Corporation. President of the Corporation from June 2014 to December 2014 and Vice President, Finance and Chief Financial Officer from 2004 to 2014.	2015	*(2)*		
JOSEPH L. WELCH, Florida, USA Corporate Director. President and Chief Executive Officer of ITC Holdings from 2003 to 2016.	2017	*(3)*		
JO MARK ZUREL, Newfoundland and Labrador, Canada President of Stonebridge Capital Inc., a private investment company since 2006.	2016	I		**C**

(1) Audit Committee, Governance and Nominating Committee and Human Resources Committee. "C" represents Chair.

(2) Mr. Perry is not a member of any committees because he is the President and Chief Executive Officer of the Corporation.

(3) Mr. Welch is not a member of any committees as he is not independent because he was President and Chief Executive Officer of ITC Holdings until October 2016. He will be considered independent in November 2019.

The following table sets out the name, province or state, and country of residence of each of the executive officers of Fortis and indicates the office held and principal occupations of the executive officers during the five preceding years.

Name, Residence, Principal Occupation During the Five Preceding Years	Office
BARRY V. PERRY, Newfoundland and Labrador, Canada President and Chief Executive Officer since January 2015. President from June 2014 to January 2015. Vice President, Finance and Chief Financial Officer from 2004 to June 2014.	President and Chief Executive Officer
JOCELYN H. PERRY, Newfoundland and Labrador, Canada Executive Vice President, Chief Financial Officer since June 2018. President and Chief Executive Officer of Newfoundland Power from 2017 to May 2018, Chief Financial Officer and Chief Operating Officer from 2016 to 2017 and Vice President, Finance & Chief Financial Officer from 2007 to 2016.	Executive Vice President, Chief Financial Officer
PHONSE J. DELANEY, Alberta, Canada Executive Vice President, Chief Information Officer since June 2017. President and Chief Executive Officer of FortisAlberta from 2014 to June 2017.	Executive Vice President, Chief Information Officer
NORA M. DUKE, Newfoundland and Labrador, Canada Executive Vice President, Sustainability and Chief Human Resource Officer since December 2017 and Executive Vice President, Corporate Services and Chief Human Resource Officer from August 2015 to December 2017. President and Chief Executive Officer of Fortis Properties from 2008 to August 2015.	Executive Vice President, Sustainability and Chief Human Resource Officer
DAVID G. HUTCHENS, Arizona, USA Executive Vice President, Western Utility Operations since January 2018 and President and Chief Executive Officer of UNS Energy since May 2014. President and Chief Operating Officer of UNS Energy from 2013 to May 2014.	Executive Vice President, Western Utility Operations
JAMES P. LAURITO, Florida, USA Executive Vice President, Business Development since April 2016. President and Chief Executive Officer of Central Hudson from 2010 to April 2016.	Executive Vice President, Business Development
JAMES R. REID, Ontario, Canada Executive Vice President, Chief Legal Officer and Corporate Secretary since March 2018. Partner with Davies Ward Phillips & Vineberg LLP from 2003 to March 2018.	Executive Vice President, Chief Legal Officer and Corporate Secretary
GARY J. SMITH, Newfoundland and Labrador, Canada Executive Vice President, Eastern Canadian and Caribbean Operations since June 2017. President and Chief Executive Officer of Newfoundland Power from 2014 to June 2017 and Vice President, Customer Operations and Engineering from 2008 to 2014.	Executive Vice President, Eastern Canadian and Caribbean Operations
STEPHANIE A. AMAIMO, Michigan, USA Vice President, Investor Relations since October 2017. Director, Investor Relations from 2016 to October 2017. Director, Investor Relations at ITC Holdings from 2015 to 2016 and Manager, Financial Planning and Analysis from 2013 to 2015.	Vice President, Investor Relations
KAREN J. GOSSE, Newfoundland and Labrador, Canada Vice President, Treasury and Planning since April 2018. Vice President, Planning and Forecasting from 2015 to April 2018. Vice President, Finance, and Chief Financial Officer of Fortis Properties from 2013 until 2015.	Vice President, Treasury and Planning
KAREN M. MCCARTHY, Newfoundland and Labrador, Canada Vice President, Communications and Corporate Affairs since May 2018. Director, Communications and Corporate Affairs from 2016 to May 2018. Director, Customer and Corporate Relations of Newfoundland Power from 2014 to 2016 and Manager, Corporate Affairs and Communications from 2013 to 2014.	Vice President, Communications and Corporate Affairs
REGAN P. O'DEA, Newfoundland and Labrador, Canada Vice President, General Counsel since May 2017 and Associate General Counsel from 2014 to May 2017.	Vice President, General Counsel
JAMIE D. ROBERTS, Newfoundland and Labrador, Canada Vice President, Controller since March 2013.	Vice President, Controller

As at December 31, 2018, the directors and executive officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 2,416,788 common shares, representing 0.56% of the issued and outstanding common shares of Fortis. The common shares are the only voting securities of the Corporation.

AUDIT COMMITTEE

Members

The members of the Corporation's Audit Committee are Tracey C. Ball (Chair), Lawrence T. Borgard, Maura J. Clark, Margarita K. Dilley, Julie A. Dobson, Douglas J. Haughey and Jo Mark Zurel. All members of the Audit Committee are independent and financially literate as those terms are defined by Canadian and U.S. securities laws and TSX and NYSE requirements. In addition, the Board has determined that Tracey C. Ball, Maura J. Clark, Margarita K. Dilley and Jo Mark Zurel are financial experts and has designated each of them as "audit committee financial experts" under U.S. securities laws.

The Corporation's Audit Committee Mandate, effective as of January 1, 2019, is attached as Exhibit "C" to this AIF.

Education and Experience

The education and experience of each Audit Committee member that is relevant to such member's responsibilities as a member of the Audit Committee are set out below.

Committee Member	Relevant Education and Experience
TRACEY C. BALL ***(Chair)***	Ms. Ball retired in September 2014 as Executive Vice President and Chief Financial Officer of Canadian Western Bank Group. Ms. Ball has served on several private and public sector boards, including the Province of Alberta Audit Committee and the Financial Executives Institute of Canada. She graduated from Simon Fraser University with a Bachelor of Arts (Commerce). She is a member of the Chartered Professional Accountants of Alberta and the Chartered Professional Accountants of British Columbia. Ms. Ball was elected as a Fellow of the Chartered Professional Accountants of Alberta in 2007. She holds an ICD.D designation from the Institute of Corporate Directors.
LAWRENCE T. BORGARD	Mr. Borgard retired from Integrys Energy Group in 2015 where he was President and Chief Operating Officer and the Chief Executive Officer of each of Integrys' six regulated electric and natural gas utilities. Mr. Borgard graduated from Michigan State University with a Bachelor of Science (Electrical Engineering) and the University of Wisconsin-Oshkosh with an MBA. He also attended the Advanced Management Program at Harvard University Business School.
MAURA J. CLARK	Ms. Clark retired from Direct Energy, a subsidiary of Centrica plc, in March 2014 where she was President of Direct Energy Business, a leading energy retailer in Canada and the United States. Previously Ms. Clark was Executive Vice President of North American Strategy and Mergers and Acquisitions for Direct Energy. Ms. Clark's prior experience includes investment banking and serving as Chief Financial Officer of an independent oil refining and marketing company. Ms. Clark graduated from Queen's University with a Bachelor of Arts in Economics. She is a member of the Association of Chartered Professional Accountants of Ontario.
MARGARITA K. DILLEY	Ms. Dilley retired from ASTROLINK International LLC in 2004, an international wireless broadband telecommunications company, where she was Vice President and Chief Financial Officer. Ms. Dilley's prior experience includes serving as Director, Strategy & Corporate Development as well as Treasurer for Intelsat. Ms. Dilley graduated from Cornell University with a Bachelor of Arts, from Columbia University with a Master of Arts and from Wharton Graduate School, University of Pennsylvania with an MBA.
JULIE A. DOBSON	Ms. Dobson is Non-Executive Chairman of Telebright, Inc. a private firm established in 1989, where she oversees the development of management software applications and mobile applications for the business to business and business to consumer markets. She was Chief Operating Officer at Telecorp PCS, Inc. and held various senior management positions with Bell Atlantic Corporation during her 18-year career with the company. Ms. Dobson graduated from the College of William and Mary with a Bachelor of Science and from the University of Pittsburgh with an MBA.
DOUGLAS J. HAUGHEY	Mr. Haughey, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation. Prior to that, he served as President and Chief Executive Officer of Provident Energy Ltd. and held several executive roles with Spectra Energy and predecessor companies. He graduated from the University of Regina with a Bachelor of Business Administration and from the University of Calgary with an MBA. Mr. Haughey holds an ICD.D designation from the Institute of Corporate Directors.
JO MARK ZUREL	Mr. Zurel is president of Stonebridge Capital Inc., a private investment company, and a corporate director. From 1998 to 2006, Mr. Zurel was Senior Vice-President and Chief Financial Officer of CHC Helicopter Corporation. Mr. Zurel graduated from Dalhousie University with a Bachelor of Commerce and is a Fellow of the Association of Chartered Professional Accountants of Newfoundland and Labrador. He holds an ICD.D designation from the Institute of Corporate Directors.

Pre-Approval Policies and Procedures

The Audit Committee has established a policy that requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's external auditor. The Pre-Approval Policy for Independent Auditor Services describes the services that may be contracted from the external auditor and the related limitations and authorization procedures. This policy defines prohibited services, including but not limited to bookkeeping, valuations, internal audit and management functions, which may not be contracted from the external auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all services provided by the external auditor.

External Auditor Service Fees

The aggregate fees billed by the Corporation's external auditors during each of the last two fiscal years are set out in the following table.

		Deloitte LLP *(1)*		Ernst & Young LLP *(2)*	
(thousands)	**Description of Fee Category**	**2018**	2017	**2018**	2017
Audit Fees	Represents the aggregate fees for core audit services.	**$ 9,121**	$ 7,207	$ —	$ 978
Audit-Related Fees	Represents the aggregate fees for assurance and related services that are reasonably related to the audit or review of the Corporation's financial statements and are not included under Audit Fees.	**1,462**	1,241	—	718
Tax Fees	Represents the aggregate fees for services related to tax compliance, planning and advice.	**636**	497	—	7
Other	Represents the aggregate fees for services which are not Audit Services, Audit-Related Fees or Tax Fees.	**27**	177	—	—
Total		**$ 11,246**	$ 9,122	$ —	$ 1,703

(1) The Corporation's external auditors effective as of May 4, 2017.
(2) The Corporation's external auditors up to May 3, 2017.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar in Canada for the common shares and first preference shares of Fortis is Computershare Trust Company of Canada in Montréal and Toronto.

The co-transfer agent and co-registrar in the United States for the common shares is Computershare Trust Company, N.A. in Canton, MA, Jersey City, NJ and Louisville, KY.

Computershare Trust Company of Canada
8th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

Computershare Trust Company, N.A.
Att: Stock Transfer Department
Overnight Mail Delivery: 250 Royall Street, Canton, Massachusetts 02021
Regular Mail Delivery: P.O. Box 43078, Providence, Rhode Island 02940-3070
T: 303.262.0600 or 1.800.962.4284

INTERESTS OF EXPERTS

Deloitte LLP is independent with respect to the Corporation within the meaning of the U.S. Securities Act of 1933 and the applicable rules and regulations thereunder adopted by the SEC and the Public Company Accounting Oversight Board (United States) and within the meaning of the rules of professional conduct of the Chartered Professional Accountants of Newfoundland and Labrador.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on the Corporation's website at www.fortisinc.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. The information contained on, or accessible through, any of these websites is not incorporated by reference into this document unless otherwise stated.

Additional financial information is provided in the Corporation's MD&A and 2018 Audited Consolidated Financial Statements, which are incorporated by reference in this AIF and can be found on the Corporation's website at www.fortisinc.com, on SEDAR and on EDGAR.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated March 16, 2018 for the May 3, 2018 annual meeting of shareholders.

Requests for additional copies of the above-mentioned documents, as well as this 2018 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800).

EXHIBIT A: Summary of Terms and Conditions of Authorized Securities

Common Shares

Dividends on common shares are declared at the discretion of the Board. Holders of common shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the first preference shares and second preference shares and any other class of shares of the Corporation entitled to receive dividends in priority to or ratably with the holders of the common shares, the Board may declare dividends on the common shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of common shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of first preference shares and second preference shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or ratably with the holders of the common shares.

Holders of the common shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

Preference Shares

First Preference Shares

The following is a summary of the material rights, privileges, conditions and restrictions attached to the first preference shares as a class. The specific terms of the first preference shares, including the currency in which first preference shares may be purchased and redeemed and the currency in which any dividend is payable, if other than Canadian dollars, and the extent to which the general terms described herein apply to those first preference shares, is or will be as set forth in the applicable articles of amendment of Fortis relating to such series.

Issuance in Series

The Board may from time to time issue first preference shares in one or more series. Prior to issuing shares in a series, the Board is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of first preference shares.

Priority

The shares of each series of first preference shares rank on a parity with the first preference shares of every other series and in priority to all other shares of Fortis, including the second preference shares, as to the payment of dividends, return of capital and the distribution of assets in the event of the liquidation, dissolution or winding-up of Fortis, whether voluntary or involuntary, or any other distribution of the assets of Fortis among its shareholders for the purpose of winding up its affairs.

Each series of first preference shares participates ratably with every other series of first preference shares in respect of accumulated cumulative dividends and returns of capital, if any, cumulative dividends, whether or not declared and any amount payable on the return of capital in respect of a series of first preference shares, if not paid in full.

Voting

The holders of the first preference shares are not entitled to any voting rights as a class except to the extent that voting rights may from time to time be attached to any series of first preference shares, and except as provided by law or as described below under the heading "Modification". At any meeting of the holders of first preference shares, each holder shall have one vote in respect of each first preference share held.

Redemption

Subject to the provisions of the *Corporations Act* (Newfoundland and Labrador) and any provisions relating to any particular series, Fortis, upon giving proper notice, may redeem out of capital or otherwise at any time, or from time to time, the whole or any part of the then outstanding first preference shares of any one or more series on payment for each such first preference share at such price or prices as may be applicable to such series. Subject to the foregoing, if only a part of the then outstanding first preference shares of any particular series is at any time redeemed, the shares to be redeemed will be selected by lot in such manner as the directors or the transfer agent for the first preference shares, if any, decide, or if the directors so determine, may be redeemed pro rata disregarding fractions.

Modification

The class provisions attached to the first preference shares may only be amended with the prior approval of the holders of the first preference shares, in addition to any other approvals required by the *Corporations Act* (Newfoundland and Labrador) or any other statutory provisions of like or similar effect in force from time to time.

The approval of the holders of the first preference shares with respect to any and all matters may be given by at least two-thirds of the votes cast at a meeting of the holders of the first preference shares duly called for that purpose.

First Preference Shares Authorized and Outstanding

The following table summarizes the series of first preference shares as of February 14, 2019.

	Authorized	Issued and Outstanding	Initial Yield (%)	Annual Dividend ($) *(1)*	Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date *(2)*	Redemption Value ($)	Right to Convert on a One for One Basis
Perpetual Fixed Rate								
Series F	5,000,000	5,000,000	4.90	1.2250	—	December 1, 2011	25.00	—
Series J *(3)*	8,000,000	8,000,000	4.75	1.1875	—	December 1, 2017	25.75	—
Fixed Rate Reset (4) (5)								
Series G *(6)*	9,200,000	9,200,000	5.25	1.0983	2.13	September 1, 2013	25.00	—
Series H	10,000,000	7,024,846	4.25	0.6250	1.45	June 1, 2015	25.00	Series I
Series K	12,000,000	10,000,000	4.00	1.0000	2.05	March 1, 2019	25.00	Series L
Series M	24,000,000	24,000,000	4.10	1.0250	2.48	December 1, 2019	25.00	Series N
Floating Rate Reset (5) (7)								
Series I *(3)*	10,000,000	2,975,154	2.10	—	1.45	June 1, 2015	25.50	Series H
Series L	12,000,000	—	—	—	2.05	March 1, 2024	—	Series K
Series N	24,000,000	—	—	—	2.48	December 1, 2024	—	Series M

(1) Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend as and when declared by the Board, payable in equal installments on the first day of each quarter.

(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding first preference shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption, and in the case of the first preference shares that reset, on every fifth anniversary date thereafter.

(3) First Preference Shares, Series J were redeemable at $26.00 until December 1, 2018, decreasing by $0.25 each year until December 1, 2021 and redeemable at $25.00 per share thereafter. First Preference Shares, Series I are redeemable at $25.50 per share, up to but excluding June 1, 2020, and at $25.00 per share on June 1, 2020, and on every fifth anniversary date of June 1, 2020, thereafter.

(4) On the redemption and/or conversion option date and each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus the applicable reset dividend yield.

(5) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their shares into an equal number of cumulative redeemable first preference shares of a specified series.

(6) The annual dividend per share for the First Preference Shares, Series G was reset from $0.9708 to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.

(7) The floating quarterly dividend rate will be reset every quarter based on the then current three month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.

Second Preference Shares

The rights, privileges, conditions and restrictions attaching to the second preference shares are substantially identical to those attaching to the first preference shares, except that the second preference shares are junior to the first preference shares with respect to the payment of dividends, repayment of capital and the distribution of assets of Fortis in the event of a liquidation, dissolution or winding up of Fortis.

The specific terms of the second preference shares, including the currency in which second preference shares may be purchased and redeemed and the currency in which any dividend is payable, if other than Canadian dollars, and the extent to which the general terms described in herein apply to those second preference shares, will be as set forth in the applicable articles of amendment of Fortis relating to such series.

As of February 14, 2019, there were no second preference shares issued and outstanding.

EXHIBIT B: MARKET FOR SECURITIES

Common Shares

The common shares are traded on the TSX in Canada, and on the NYSE in the U.S., in each case under the symbol FTS. The following table sets forth the reported high and low trading prices and trading volumes, on a monthly basis for the year ended December 31, 2018, for the common shares on the TSX and NYSE in Canadian Dollars and US Dollars, respectively.

2018 Trading Prices and Volumes – Common Shares						
	TSX			NYSE		
Month	High ($)	Low ($)	Volume	High (US$)	Low (US$)	Volume
January	46.00	42.56	23,833,658	36.76	34.49	6,373,078
February	43.48	39.38	27,141,195	35.35	31.41	8,235,162
March	43.83	41.52	26,194,320	34.03	32.26	6,702,318
April	43.83	41.76	15,120,177	34.19	32.83	4,541,728
May	43.60	41.31	17,886,103	33.79	31.84	3,684,268
June	42.41	40.21	18,718,490	32.02	30.88	7,246,839
July	43.18	41.71	15,867,578	33.02	31.55	6,192,773
August	43.65	42.05	17,701,954	33.42	32.11	4,534,468
September	43.14	41.67	17,025,568	33.00	32.09	4,581,920
October	44.04	40.71	33,041,713	33.84	31.37	8,895,053
November	47.06	42.60	28,786,806	35.82	32.48	6,370,720
December	47.36	43.49	27,966,319	35.86	31.80	8,971,281

Preference Shares

The First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M of Fortis are listed on the TSX under the symbols FTS.PR.F; FTS.PR.G; FTS.PR.H; FTS.PR.I; FTS.PR.J; FTS.PR.K and FTS.PR.M, respectively.

The following tables set forth the reported high and low trading prices and volumes for the First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M on a monthly basis for the year ended December 31, 2018.

2018 Trading Prices and Volumes – First Preference Shares						
	First Preference Shares, Series F			First Preference Shares, Series G		
Month	High ($)	Low ($)	Volume	High ($)	Low ($)	Volume
January	24.56	23.90	52,581	23.46	21.80	314,574
February	24.01	23.14	116,545	23.49	22.65	481,057
March	23.40	23.04	26,613	22.89	21.69	164,323
April	23.37	22.88	49,779	21.86	21.35	360,277
May	23.35	22.62	22,564	22.75	21.41	263,086
June	23.00	22.56	44,988	22.00	21.69	131,944
July	23.05	22.74	91,350	22.46	21.59	99,568
August	23.09	22.67	117,689	22.45	21.81	71,417
September	22.90	22.68	38,973	22.21	21.55	108,121
October	22.78	21.53	78,511	21.94	19.76	347,351
November	22.42	21.21	76,509	20.96	18.01	93,717
December	22.38	20.66	54,125	19.34	16.85	384,885

	First Preference Shares, Series H			First Preference Shares, Series I		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	19.27	17.95	448,894	19.41	17.10	149,365
February	18.95	18.39	58,465	19.00	18.22	60,571
March	18.55	17.72	117,162	18.69	17.69	11,052
April	18.04	17.46	48,388	17.90	17.53	13,728
May	18.96	17.83	47,539	18.84	17.85	52,500
June	18.81	18.29	138,802	18.65	18.07	106,500
July	18.80	18.20	57,802	18.85	18.21	22,735
August	18.76	18.30	153,861	19.05	18.50	16,689
September	18.58	18.21	26,453	18.90	18.42	15,800
October	18.51	17.09	292,217	19.33	17.42	67,159
November	17.94	15.61	68,366	18.33	16.26	19,705
December	16.18	14.22	145,708	16.65	13.64	37,628

	First Preference Shares, Series J			First Preference Shares, Series K		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	23.48	22.77	88,753	22.98	21.61	157,367
February	23.20	22.10	73,891	23.00	22.35	60,197
March	22.66	22.23	64,898	22.60	21.52	232,405
April	22.80	22.12	71,416	21.72	21.28	75,323
May	22.60	21.89	126,261	22.70	21.58	108,200
June	22.28	21.90	153,957	21.99	21.50	52,196
July	22.45	22.10	80,266	21.88	21.37	65,424
August	22.45	21.92	182,692	22.06	21.58	346,042
September	22.08	21.87	108,890	21.87	21.47	112,970
October	22.03	20.77	153,462	21.94	20.05	237,944
November	21.71	20.45	93,375	21.11	18.05	163,491
December	21.88	20.26	138,827	18.41	16.17	180,451

	First Preference Shares, Series M		
Month	**High ($)**	**Low ($)**	**Volume**
January	24.41	23.65	921,049
February	24.45	23.67	218,630
March	23.96	23.28	158,451
April	23.66	23.26	175,864
May	24.07	23.35	1,231,722
June	25.00	23.40	412,482
July	23.98	23.24	195,966
August	24.22	23.71	75,810
September	24.20	23.64	178,167
October	24.07	22.15	203,354
November	23.23	19.56	208,333
December	19.97	17.45	505,883

EXHIBIT C: AUDIT COMMITTEE MANDATE

1.0 PURPOSE AND AUTHORITY

1.1 The purpose of the Committee is to assist the Board with its oversight of:

(a) the integrity of the Corporation's financial statements, financial disclosures and internal controls over financial reporting;

(b) the Corporation's compliance with related legal and regulatory requirements;

(c) the qualifications, independence and performance of the Independent Auditor and Internal Auditor;

(d) the related policies of the Corporation set out herein; and

(e) other matters set out herein or otherwise delegated to the Committee by the Board.

1.2 Consistent with this purpose, the Committee should encourage continuous improvement of, and foster adherence to, the Corporation's policies, procedures and practices at all levels. The Committee should also provide for open communication among the Independent Auditor, the Internal Auditor, Management and the Board.

1.3 To perform its duties and responsibilities, the Committee has the authority to: (i) conduct investigations into any matters within its scope of responsibility; (ii) obtain advice and assistance from outside legal, accounting, or other advisors as the Committee may deem appropriate, in its sole discretion; and (iii) meet with and seek any information it requires from external parties or employees, officers and directors of the Corporation or any affiliate of the Corporation.

1.4 The Corporation will provide appropriate funding, as determined by the Committee, for compensation to the Independent Auditor, to any independent counsel or other advisors that the Committee chooses to engage, and for payment of ordinary administrative expenses of the Committee that are necessary and appropriate in carrying out its duties.

1.5 The Committee will primarily fulfill its responsibilities by carrying out the activities set out in this Mandate.

2.0 DEFINITIONS

2.1 In this Mandate:

(a) **"Board"** means the board of directors of the Corporation;

(b) **"Chair"** means the Chair of the Committee;

(c) **"Committee"** means the audit committee appointed by the Board pursuant to this Mandate;

(d) **"Core Audit Services"** means services necessary to: (i) audit the Corporation's annual consolidated or non-consolidated financial statements; (ii) review the Corporation's interim condensed consolidated financial statements; and (iii) audit internal controls over financial reporting in accordance with the requirements of the Sarbanes Oxley Act of 2002;

(e) **"Corporation"** means Fortis Inc.;

(f) **"CPAB"** means the Canadian Public Accountability Board or its successor;

(g) **"Director"** means a member of the Board;

(h) **"ERM Program"** means the Corporation's Enterprise Risk Management Program that incorporates an effective risk management framework and applies a logical and systematic methodology to identify, evaluate, treat, monitor and communicate key corporate risks;

(i) **"Financial Expert"** means an "audit committee financial expert" as defined in Item 407(d)(5) of SEC Regulation S-K;

(j) **"Financially Literate"** means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

(k) **"Governance and Nominating Committee"** means the governance and nominating committee of the Board;

(l) **"Independent"** means, in the context of a Member and in accordance with applicable law and stock exchange requirements, free from any direct or indirect material relationship with the Corporation and its subsidiaries which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment;

(m) **"Independent Auditor"** means the firm of chartered professional accountants, registered with the CPAB and the PCAOB, and appointed by the Shareholders to act as external auditor;

(n) **"Internal Auditor"** means the person(s) employed or engaged by the Corporation to perform the internal audit function of the Corporation;

(o) **"Management"** means the senior officers of the Corporation;

(p) **"Mandate"** means this mandate of the Committee;

(q) **"MD&A"** means the Corporation's management discussion and analysis prepared in accordance with the requirements of National Instrument 51-102F1 and the SEC in respect of the Corporation's annual consolidated and interim condensed consolidated financial statements;

(r) **"Member"** means a Director appointed to the Committee;

(s) **"NYSE"** means the New York Stock Exchange;

(t) **"PCAOB"** means the Public Company Accounting Oversight Board or its successor;

(u) **"Related Party Transactions"** means those transactions required to be disclosed under Items 404(a) and 404(b) of SEC Regulation S-K and required to be evaluated by an appropriate group within the Corporation pursuant to Section 314.00 of the NYSE Listed Company Manual which, without limiting the foregoing, are transactions between: (i) executive officers, directors, principal shareholders or their immediate family members; and (ii) the Corporation;

(v) **"SEC"** means the United States Securities and Exchange Commission; and

(w) **"Shareholders"** means the shareholders of the Corporation.

3.0 ESTABLISHMENT AND COMPOSITION OF COMMITTEE

3.1 The Committee will be comprised of three (3) or more Directors, each of whom is Independent and Financially Literate. No Member may be a member of Management or an employee of the Corporation or of any affiliate of the Corporation. The Board will appoint to the Committee at least one Director who is a Financial Expert.

3.2 Members will be appointed by the Board at the annual organizational meeting of the Board, or at other times as may be necessary, provided, however, that if the appointment of Members is not so made at such a meeting, the Directors who are then serving as Members will continue as Members until their successors are appointed. Each Member shall serve until his or her successor is appointed, unless he or she shall resign or be removed by the Board or he or she shall otherwise cease to be a Director.

3.3 The Board may appoint a Member to fill a vacancy which occurs on the Committee between annual elections of Directors. If a vacancy exists on the Committee, the remaining Members will exercise all of the powers of the Committee so long as at least three (3) Members remain in office.

3.4 Any Member may be removed from the Committee by a resolution of the Board.

3.5 No Member will serve on more than three public company audit committees without the approval of the Board.

3.6 The Board will appoint a Chair on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize, provided, however, that if the appointment of the Chair is not so made, the Director who is then serving as Chair will continue as Chair until his or her successor is appointed. The Board will periodically rotate the Chair and will make reasonable efforts to rotate the Chair every four years. Such rotation will occur after the annual general meeting of Shareholders.

4.0 COMMITTEE MEETINGS

4.1 The Committee will meet at least quarterly and will meet at such other times during the year as it deems appropriate. Meetings of the Committee will be held at the call of: (i) the Chair; or (ii) any two Members; or (iii) the Independent Auditor; and may be held in-person, by means of remote communication or a combination thereof. The time and place of the meetings of the Committee and the procedures for such meetings will be determined by the Committee.

4.2 The Chief Executive Officer, the Chief Financial Officer, the Independent Auditor and the Internal Auditor will receive notice of and, unless otherwise determined by the Chair, will attend all meetings of the Committee. For clarity, the Independent Auditor must attend the Committee meetings at which the Corporation's annual audited consolidated and non-consolidated financial statements and interim unaudited condensed consolidated financial statements are reviewed.

4.3 A quorum at any meeting of the Committee will be at least three (3) or more Members.

4.4 Each Member will have the right to vote on matters that come before the Committee.

4.5 Any matter to be determined by the Committee will be decided by a majority of votes cast at a meeting of the Committee at which such matter is considered. Actions of the Committee may also be taken by an instrument or instruments in writing signed by all of the Members, and such actions will be effective as though they had been decided by a majority of votes cast at a meeting of the Committee called for such purpose.

4.6 The Chair will act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting will appoint one of such Members to act as Chair of the meeting.

4.7 Unless otherwise determined by the Chair, the Corporate Secretary of the Corporation will act as secretary of all meetings of the Committee.

4.8 The Committee will periodically meet separately with Management, the Internal Auditor and the Independent Auditor to discuss any matters that the Committee or any of these persons or firms believes should be discussed privately.

5.0 SPECIFIC RESPONSIBILITIES AND DUTIES OF THE COMMITTEE

A. Independent Auditor

5.1 In consultation and coordination with the subsidiary audit committees, the Committee will be directly responsible for the appointment (through a recommendation to the Board for the appointment by Shareholders), compensation and retention of the Independent Auditor.

5.2 The Committee will oversee the work of the Independent Auditor in connection with the Core Audit Services and any other services performed for the Corporation. The Independent Auditor will report directly to the Committee and the Committee has the authority to communicate directly with the Independent Auditor.

5.3 The Committee will oversee the resolution of any disagreements between Management and the Independent Auditor. The Committee will discuss with the Independent Auditor the matters required to be discussed under PCAOB Auditing Standard No. 1301 relating to the conduct of the audit, including any problems or difficulties encountered and Management's responses thereto and any restrictions on the scope of activities or access to requested information.

5.4 The Committee will pre-approve all services performed by the Independent Auditor in accordance with the Corporation's Pre-Approval Policy for Independent Auditor Services. For any service, other than Core Audit Services, requiring specific pre-approval in accordance with such policy, the Committee may delegate pre-approval authority to one or more of its Members. Currently, pre-approval authority in this regard has been delegated to the Chair or, in that person's absence, the Chair of the Board who is a Member. Delegates must report all pre-approval decisions to the Committee at the next scheduled meeting.

5.5 The Committee will annually obtain and review a report from the Independent Auditor delineating all relationships between the Independent Auditor and the Corporation and its subsidiaries in accordance with Item 407(d) of SEC Regulation S-K and Section 303A.07 of the NYSE Listed Company Manual and addressing the matters set forth in PCAOB Rule 3526. The Committee will use reasonable efforts, including discussion with the Independent Auditor, to satisfy itself as to the Independent Auditor's independence in accordance with Canadian generally accepted auditing standards and PCAOB standards, the requirements and interpretative guidance of SEC Regulation S-X and any other applicable regulations and professional standards. The Committee will discuss any potential independence issues with the Board and recommend any commensurate action that the Committee deems appropriate.

5.6 The Committee will review and evaluate the qualifications and performance of the Independent Auditor and its lead engagement partner. Without limiting the generality of the foregoing, the Committee will:

(a) review and discuss with Management and separately with the Independent Auditor the results of the Corporation's annual Independent Auditor assessment process; and

(b) at least annually, obtain and review a report from the Independent Auditor describing the firm's internal quality control process and procedures, including any material issues raised by the most recent internal quality-control review or peer review, or by any inquiry or investigation by governmental or professional authorities (including without limitation the PCAOB and the CPAB) within the preceding five years with respect to independent audits carried out by the Independent Auditor, and any steps taken to deal with such issues.

The Committee will discuss any arising issues with the Board and recommend any commensurate action that the Committee deems appropriate.

5.7 The Committee will ensure the rotation of the audit partner(s) as required by applicable law and consider the need for rotation of the Independent Auditor.

5.8 The Committee will meet with the Independent Auditor prior to the audit to discuss the planning and staffing of the audit, including the general approach, scope, areas subject to significant risk of material misstatement, estimated fees and other terms of engagement.

B. Financial Reporting

5.9 In consultation with Management, the Independent Auditor and the Internal Auditor, the Committee will review and satisfy itself as to: (i) the integrity of the Corporation's internal and external financial reporting processes; (ii) the adequacy and effectiveness of the Corporation's disclosure controls and procedures (including those pertaining to the review of disclosure containing financial information extracted or derived from the Corporation's financial statements) and internal controls over financial reporting; and (iii) the competence of the Corporation's personnel responsible for accounting and financial reporting. Without limiting the generality of the foregoing, the Committee will receive and review:

(a) reports regarding: (i) critical accounting estimates, policies and practices; (ii) goodwill impairment testing; (iii) derivatives and hedges; and (iv) the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the Corporation's financial statements;

(b) analyses by Management and the Independent Auditor regarding significant financial reporting issues and judgements made in connection with the preparation of the Corporation's consolidated financial statements including: (i) alternative treatments of financial information within generally accepted accounting principles related to material matters that have been discussed with Management, their ramifications and the treatment preferred by the Independent Auditor; (ii) major issues regarding accounting principles and presentations, including significant changes in the selection or application of accounting principles; and (iii) major issues regarding the adequacy of the Corporation's internal controls and any specific audit steps adopted in light of material weaknesses or significant deficiencies in internal controls; and

(c) other material written communication between Management and the Independent Auditor.

5.10 The Committee will, prior to external release if applicable, review and discuss with Management and the Independent Auditor, and with others as it deems appropriate:

(a) the Corporation's annual audited consolidated and non-consolidated financial statements and interim unaudited condensed consolidated financial statements and the Independent Auditor's related attestation reports as well as any related MD&As;

(b) Management's report and the Independent Auditor's audit report on internal controls over financial reporting;

(c) significant reports or summaries thereof pertaining to the Corporation's processes for compliance with the requirements of the Sarbanes Oxley Act of 2002 with respect to internal controls over financial reporting;

(d) the Independent Auditor's quarterly review reports and annual audit results report summarizing the scope, status, results and recommendations of the quarterly reviews of the Corporation's interim condensed consolidated financial statements and of the audit of the Corporation's annual consolidated financial statements and related audit of internal controls over financial reporting, and also containing at least: (i) the

communications with respect thereto between the Independent Auditor and the Committee required by PCAOB Auditing Standard No. 1301 and any other applicable regulations and professional standards, including without limitation schedules of corrected and uncorrected account and disclosure misstatements and significant deficiencies and material weaknesses in internal controls; (ii) the (at least) annual independence communication required by PCAOB Rule 3526; (iii) the Management representation letter; and (iv) the documentation and communication required quarterly from the Independent Auditor under the Corporation's *Pre-Approval Policy for Independent Auditor Services;*

(e) the *Report to Shareholders* contained in the Corporation's annual report; and

(f) any other document that the Committee determines should be reviewed and discussed with Management and the Independent Auditor or for which a legal or regulatory requirement in that regard exists.

5.11 The Committee will, prior to external release, review and discuss with Management and with others as it deems appropriate, the financial information to be disclosed in the Corporation's interim and annual earnings media releases or other media releases.

5.12 The Committee will recommend the Corporation's annual audited consolidated financial statements together with the Independent Auditor's audit report thereon and on internal controls over financial reporting, Management's report on internal controls over financial reporting, MD&A, earnings media release, and *Report to Shareholders* for approval by the Board and subsequent external release as well as inclusion of the noted financial statements in the Corporation's annual report on Form 40-F. The Committee will approve the external release of the Corporation's interim unaudited condensed consolidated financial statements and related interim MD&As and earning media releases on behalf of the Board.

5.13 The Committee will, prior to external release, review and discuss with Management and with others as it deems appropriate, and recommend for approval by the Board:

(a) any earnings and dividend guidance to be provided by the Corporation;

(b) the Annual Information Form and Management Information Circular to be filed by the Corporation;

(c) any prospectus or other offering documents and documents related thereto for the issuance of securities by the Corporation; and

(d) other financial information and disclosure documents to be released publicly.

5.14 The Committee will review, and discuss with Management and with others as it deems appropriate, the disclosures made by the Chief Executive Officer and Chief Financial Officer of the Corporation pursuant to their certification of the Corporation's annual and quarterly reports regarding significant deficiencies or material weaknesses in the design or operation of internal controls over financial reporting and any fraud involving Management or other employees.

5.15 The Committee will use reasonable efforts to satisfy itself as to the appropriateness of the Corporation's material financing and tax structures.

5.16 The Committee will review, and discuss with Management and with others as it deems appropriate, financial information provided to analysts and ratings agencies. Such discussions may be in general terms (i.e. discussion of the types of information to be disclosed and the types of presentations to be made) and need not occur in advance of each release of information.

5.17 The Committee will prepare, or cause to be prepared, any reports of the Committee required to be included in the Corporation's public disclosures or otherwise required by applicable law.

5.18 The Committee will review, discuss with Management and with others as it deems appropriate, and approve all Related Party Transactions and the disclosure thereof.

C. Internal Audit

5.19 The Committee will be responsible for the oversight of the Internal Auditor in accordance with the Policy on the Role of the Internal Audit Function and has the authority to communicate directly with the Internal Auditor.

5.20 The Committee will review, discuss with the Internal Auditor and others as it deems appropriate and approve the annual internal audit plan.

5.21 The Committee will review and discuss with Management and the Internal Auditor and others as it deems appropriate the quarterly internal audit reports prepared for the Committee (which will incorporate all significant activities of the internal audit function for the quarter) and any Management responses thereto.

5.22 The Committee will periodically discuss with the Internal Auditor any significant difficulties, disagreements with Management, or scope restrictions encountered in the course of carrying out the work of the internal audit function.

5.23 The Committee will periodically discuss with the Internal Auditor the internal audit function's responsibility, budget and staffing.

5.24 The Committee will satisfy itself as to the performance of the internal audit function and the qualifications of its staff.

D. Risk Management and Other

5.25 The Committee will be responsible for the oversight of the Corporation's ERM Program.

5.26 The Committee will review and discuss with Management, the Internal Auditor and others as it deems appropriate Management's report regarding identifying, assessing and addressing significant risks and related matters pursuant to the ERM Program.

5.27 The Committee will review and discuss with Management and others as it deems appropriate the quarterly report prepared by Management regarding significant litigation and other significant legal matters that could have a significant impact on the Corporation or its financial statements.

5.28 The Committee will be responsible for the oversight of the Corporation's insurance program.

E. Policies and Mandate

5.29 The Committee is responsible for the oversight of the following policies:

(a) Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing (including overseeing procedures for the receipt, retention, and treatment of complaints regarding accounting, internal controls, or auditing matters as well as procedures for confidential, anonymous submissions by employees regarding questionable accounting or auditing matters as required by applicable law);

(b) Derivative Instruments and Hedging Policy;

(c) Pre-Approval Policy for Independent Auditor Services;

(d) Hiring from Independent Auditing Firms Policy;

(e) Policy on the Role of the Internal Audit Function;

(f) Disclosure Policy; and

(g) other policies that may be established from time-to-time regarding accounting, financial reporting, disclosure controls and procedures, internal controls over financial reporting, oversight of the external audit of the Corporation's financial statements, and oversight of the internal audit function.

5.30 The Committee will periodically review this Mandate and the policies in Section 5.29 and recommend any necessary amendments to the Governance and Nominating Committee for consideration and recommendation to the Board as deemed appropriate.

6.0 REPORTING

6.1 The Chair, or another designated Member, shall report to the Board at each regular meeting on those matters that were dealt with by the Committee since the last regular meeting of the Board.

7.0 REMUNERATION OF MEMBERS

7.1 Members and the Chair will receive such remuneration for their service on the Committee as the Board may determine from time to time, having considered the recommendation of the Committee.

7.2 No Member may earn fees from the Corporation or any of its subsidiaries other than Directors' fees (which fees may include a combination of cash, benefits, deferred share units and common shares or other equity securities of the Corporation). For greater certainty, no Member will accept, directly or indirectly, any consulting, advisory or other compensatory fee from the Corporation.

8.0 GENERAL

8.1 This Mandate will be posted on the Corporation's corporate website at www.fortisinc.com.

8.2 The Committee will annually review its own effectiveness and performance.

8.3 The Committee will perform any other activities consistent with this Mandate, the Corporation’s bylaws and applicable law that the Board or Committee determines are necessary or appropriate.

8.4 The Committee is not responsible for certifying the accuracy or completeness of the Corporation's financial statements or their presentation in accordance with generally accepted accounting principles, or for guaranteeing the accuracy of the attestation reports of the Independent Auditor. The fundamental responsibility for the Corporation's financial statements and disclosures and internal controls over financial reporting rests with Management and, in accordance with its professional responsibilities, the Independent Auditor. Nothing in this Mandate is intended to modify or augment the obligations of the Corporation or the fiduciary duties of the Committee or the Board under applicable law.

EXHIBIT D: MATERIAL CONTRACTS

The following are the material contracts of Fortis filed on SEDAR and EDGAR during 2018 or which were entered into prior to 2018 and are still in effect. Requests for additional copies of these material contracts should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). All such contracts are also available under the Corporation's profile at www.sedar.com and www.sec.gov.

Revolving Credit Facility

Fortis is a party to a Third Amended and Restated Credit Facility dated July 31, 2017, with The Bank of Nova Scotia as underwriter, sole lead arranger and bookrunner and administrative agent and Canadian Imperial Bank of Commerce and Royal Bank of Canada as co-syndication agents, and the lenders party thereto from time to time, as amended by the First Amending Agreement dated May 11, 2018 between Fortis, The Bank of Nova Scotia and the lenders named therein. The Third Amended and Restated Credit Facility is a $1.3 billion unsecured committed revolving credit facility and contains the terms and conditions upon which such credit is available to Fortis during the duration of the facility. The Third Amended and Restated Credit Facility contains customary representations and warranties, affirmative and negative covenants and events of default. Customary fees are payable by Fortis in respect of the facility and amounts outstanding under the facility bear interest at market rates.

Shareholders' Agreement

On October 14, 2016, ITC Investment Holdings, ITC Holdings, FortisUS and Eiffel Investment Pte Ltd (an affiliate of GIC and successor to Finn Investment Pte Ltd) entered into a Shareholders' Agreement which governs the rights of the parties in their respective capacities as direct or indirect shareholders of ITC Holdings. The Shareholders' Agreement provides certain customary rights to Eiffel Investment Pte Ltd, including the right to appoint one director to the boards of ITC Investment Holdings and ITC Holdings as long as it owns at least 9.95% (except in specified instances of dilution) of the outstanding common stock of ITC Investment Holdings.

Under the terms of the Shareholders' Agreement, Eiffel Investment Pte Ltd has certain minority approval rights relating to ITC Investment Holdings and ITC Holdings, subject to maintenance of certain ownership thresholds with respect to ITC Investment Holdings, including with respect to: (i) amendments to charter documents, (ii) changes in board size, (iii) issuances of equity, (iv) business combinations that would impact Eiffel Investment Pte Ltd differently than other shareholders, (v) insolvency, (vi) certain acquisitions of, investments in, or joint ventures relating to non-core assets, or certain material sales or dispositions of core assets, (vii) in limited circumstances, the incurrence of indebtedness by ITC Investment Holdings, ITC Holdings or its subsidiaries or the taking of certain actions that would reasonably be expected to result in the long-term unsecured indebtedness of ITC Investment Holdings, ITC Holdings and its subsidiaries being rated below investment grade, (viii) actions that would cause a ratio of ITC Holding's cash flow to debt to exceed an agreed targeted threshold, (ix) limitations on corporate overhead costs paid by ITC Holdings to Fortis and (x) expansion of the core business outside ITC Holdings' current regulatory jurisdictions. The Shareholders' Agreement also provides for a dividend policy, which can be amended only with the approval of all the independent directors of ITC Investment Holdings.

Indenture and First Supplemental Indenture

On October 4, 2016, Fortis entered into an Indenture and a First Supplement thereto with The Bank of New York Mellon, as U.S. trustee, and BNY Trust Company of Canada, as Canadian co-trustee. The Indenture and the First Supplement set forth the terms of the Corporation's outstanding US$500 million aggregate principal amount of 2.100% Unsecured Notes due 2021 and US$1.5 billion aggregate principal amount of 3.055% Unsecured Notes due 2026. The Indenture contains customary covenants, events of default and rights for the benefit of security holders and the trustees. An unlimited amount of debt securities may be issued under the Indenture, which is governed by the laws of the State of New York.

Exhibit 99.2

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2018 and 2017

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Management's Report on Internal Control over Financial Reporting

Management of Fortis Inc. and its subsidiaries (the "Corporation") is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR"). The Corporation's ICFR is designed by, or under the supervision of, the Corporation's President and Chief Executive Officer ("CEO") and Executive Vice President, Chief Financial Officer ("CFO") and effected by the Corporation's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including its CEO and CFO, assessed the effectiveness of the Corporation's ICFR as at December 31, 2018, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as at December 31, 2018, the Corporation's ICFR was effective.

The Corporation's ICFR as at December 31, 2018 has been audited by Deloitte LLP, an Independent Registered Public Accounting Firm, which also audited the Corporation's consolidated financial statements for the year ended December 31, 2018. Deloitte LLP issued an unqualified opinion for both audits.

February 14, 2019

/s/ Barry V. Perry

Barry V. Perry
President and Chief Executive Officer, Fortis Inc.

/s/ Jocelyn H. Perry

Jocelyn H. Perry
Executive Vice President, Chief Financial Officer, Fortis Inc.

St. John's, Canada

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of Fortis Inc. and subsidiaries (the "Corporation") as at December 31, 2018 and 2017, the related consolidated statements of earnings, comprehensive income, cash flows, and changes in equity for each of the two years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Corporation's internal control over financial reporting as at December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 14, 2019, expressed an unqualified opinion on the Corporation's internal control over financial reporting.

Basis for Opinion
These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the Corporation's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 14, 2019

We have served as the Corporation's auditor since 2017.

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on Internal Control over Financial Reporting
We have audited the internal control over financial reporting of Fortis Inc. and subsidiaries (the "Corporation") as at December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as at December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements as at and for the year ended December 31, 2018, of the Corporation and our report dated February 14, 2019, expressed an unqualified opinion on those financial statements.

Basis for Opinion
The Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 14, 2019

FORTIS INC.

Consolidated Balance Sheets

As at December 31

(in millions of Canadian dollars)

	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	**$ 332**	$ 327
Accounts receivable and other current assets (Note 7)	**1,357**	1,131
Prepaid expenses	**84**	79
Inventories (Note 8)	**398**	367
Regulatory assets (Note 9)	**324**	303
Assets held for sale (Note 10)	**766**	—
Total current assets	**3,261**	2,207
Other assets (Note 11)	**552**	480
Regulatory assets (Note 9)	**2,854**	2,742
Property, plant and equipment, net (Note 12)	**32,654**	29,668
Intangible assets, net (Note 13)	**1,200**	1,081
Goodwill (Note 14)	**12,530**	11,644
Total assets	**$ 53,051**	$ 47,822
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 16)	**$ 60**	$ 209
Accounts payable and other current liabilities (Note 15)	**2,289**	2,053
Regulatory liabilities (Note 9)	**656**	490
Current installments of long-term debt (Note 16)	**926**	705
Current installments of capital lease and finance obligations (Note 17)	**252**	47
Liabilities associated with assets held for sale (Note 10)	**69**	—
Total current liabilities	**4,252**	3,504
Other liabilities (Note 18)	**1,138**	1,210
Regulatory liabilities (Note 9)	**2,970**	2,956
Deferred income taxes (Note 24)	**2,686**	2,298
Long-term debt (Note 16)	**23,159**	20,691
Capital lease and finance obligations (Note 17)	**390**	414
Total liabilities	**34,595**	31,073
Commitments and contingencies (Note 30)		
Equity		
Common shares *(1)*	**11,889**	11,582
Preference shares (Note 20)	**1,623**	1,623
Additional paid-in capital	**11**	10
Accumulated other comprehensive income (Note 21)	**928**	61
Retained earnings	**2,082**	1,727
Shareholders' equity	**16,533**	15,003
Non-controlling interests	**1,923**	1,746
Total equity	**18,456**	16,749
Total liabilities and equity	**$ 53,051**	$ 47,822

(1) No par value. Unlimited authorized shares; 428.5 million and 421.1 million issued and outstanding as at December 31, 2018 and 2017, respectively

Approved on Behalf of the Board

/s/ Douglas J. Haughey — **Douglas J. Haughey, Director**

/s/ Tracey C. Ball — **Tracey C. Ball, Director**

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Earnings

For the years ended December 31

(in millions of Canadian dollars, except per share amounts)

	2018	2017
Revenue (Note 6)	**$ 8,390**	$ 8,301
Expenses		
Energy supply costs	**2,495**	2,361
Operating expenses	**2,287**	2,250
Depreciation and amortization	**1,243**	1,179
Total expenses	**6,025**	5,790
Operating income	**2,365**	2,511
Other income, net (Note 23)	**60**	116
Finance charges	**974**	914
Earnings before income tax expense	**1,451**	1,713
Income tax expense (Note 24)	**165**	588
Net earnings	**$ 1,286**	$ 1,125
Net earnings attributable to:		
Non-controlling interests	**$ 120**	$ 97
Preference equity shareholders	**66**	65
Common equity shareholders	**1,100**	963
	$ 1,286	$ 1,125
Earnings per common share (Note 19)		
Basic	**$ 2.59**	$ 2.32
Diluted	**$ 2.59**	$ 2.31

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Comprehensive Income

For the years ended December 31

(in millions of Canadian dollars)

	2018	2017
Net earnings	**$ 1,286**	$ 1,125
Other comprehensive income (loss)		
Unrealized foreign currency translation gains (losses), net of hedging activities and income tax recovery (expense) of $11 million and $(2) million, respectively	**985**	(781)
Other, net of income tax expense of $2 million and nil, respectively	**6**	(2)
	991	(783)
Comprehensive income	**$ 2,277**	$ 342
Comprehensive income (loss) attributable to:		
Non-controlling interests	**$ 244**	$ (2)
Preference equity shareholders	**66**	65
Common equity shareholders	**1,967**	279
	$ 2,277	$ 342

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Cash Flows

For the years ended December 31

(in millions of Canadian dollars)

	2018	2017
Operating activities		
Net earnings	**$ 1,286**	$ 1,125
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,107**	1,055
Amortization - intangible assets	**106**	97
Amortization - other	**30**	27
Deferred income tax expense (Note 24)	**136**	544
Equity component, allowance for funds used during construction (Note 23)	**(64)**	(74)
Other	**92**	11
Change in long-term regulatory assets and liabilities	**13**	68
Change in working capital (Note 27)	**(102)**	(97)
Cash from operating activities	**2,604**	2,756
Investing activities		
Capital expenditures - property, plant and equipment	**(3,032)**	(2,813)
Capital expenditures - intangible assets	**(186)**	(211)
Contributions in aid of construction	**106**	102
Other	**(140)**	(103)
Cash used in investing activities	**(3,252)**	(3,025)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 16)	**1,566**	2,538
Repayments of long-term debt and capital lease and finance obligations	**(563)**	(952)
Borrowings under committed credit facilities (Note 31)	**5,666**	6,461
Repayments under committed credit facilities (Note 31)	**(5,523)**	(7,480)
Net change in short-term borrowings (Note 31)	**38**	(192)
Issue of common shares, net of costs, and dividends reinvested	**34**	561
Dividends		
Common shares, net of dividends reinvested	**(459)**	(419)
Preference shares	**(66)**	(65)
Subsidiary dividends paid to non-controlling interests	**(85)**	(109)
Other	**36**	(4)
Cash from financing activities	**644**	339
Effect of exchange rate changes on cash and cash equivalents	**24**	(12)
Change in cash and cash equivalents	**20**	58
Less: Cash associated with assets held for sale (Note 10)	**(15)**	—
Cash and cash equivalents, beginning of year	**327**	269
Cash and cash equivalents, end of year	**$ 332**	$ 327

Supplementary Cash Flow Information (Note 27)

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Changes in Equity

For the years ended December 31, 2018 and 2017

(in millions of Canadian dollars, except share numbers)

	Common Shares *(millions)*	Common Shares	Preference Shares *(Note 20)*	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss) *(Note 21)*	Retained Earnings	Non-Controlling Interests	Total Equity
As at December 31, 2017	**421.1**	**$ 11,582**	**$ 1,623**	**$ 10**	**$ 61**	**$ 1,727**	**$ 1,746**	**$16,749**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,166**	**120**	**1,286**
Other comprehensive income	**—**	**—**	**—**	**—**	**867**	**—**	**124**	**991**
Common shares issued	**7.4**	**307**	**—**	**(1)**	**—**	**—**	**—**	**306**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(85)**	**(85)**
Dividends declared on common shares ($1.75 per share)	**—**	**—**	**—**	**—**	**—**	**(745)**	**—**	**(745)**
Dividends declared on preference shares	**—**	**—**	**—**	**—**	**—**	**(66)**	**—**	**(66)**
Other	**—**	**—**	**—**	**2**	**—**	**—**	**18**	**20**
As at December 31, 2018	**428.5**	**$ 11,889**	**$ 1,623**	**$ 11**	**$ 928**	**$ 2,082**	**$ 1,923**	**$18,456**
As at December 31, 2016	401.5	$ 10,762	$ 1,623	$ 12	$ 745	$ 1,455	$ 1,853	$16,450
Net earnings	—	—	—	—	—	1,028	97	1,125
Other comprehensive loss	—	—	—	—	(684)	—	(99)	(783)
Common shares issued	19.6	820	—	(5)	—	—	—	815
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(109)	(109)
Dividends declared on common shares ($1.65 per share)	—	—	—	—	—	(691)	—	(691)
Dividends declared on preference shares	—	—	—	—	—	(65)	—	(65)
Other	—	—	—	3	—	—	4	7
As at December 31, 2017	421.1	$ 11,582	$ 1,623	$ 10	$ 61	$ 1,727	$ 1,746	$16,749

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is principally a North American electric and gas utility holding company. Entities within the reporting segments that follow operate with substantial autonomy.

Regulated Utilities

ITC: Primarily comprised of ITC Holdings Corp., ITC Investment Holdings Inc. 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. Fortis owns 80.1% of ITC and an affiliate of GIC Private Limited owns a 19.9% minority interest.

ITC owns and operates high-voltage transmission lines in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma.

UNS Energy: Comprised of UNS Energy Corporation, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas").

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County and parts of Cochise County, as well as in Santa Cruz and Mohave counties. TEP also sells wholesale electricity to other entities in the western United States. Together they own generation capacity of 3,377 megawatts ("MW"), including 57 MW of solar capacity. Several generating assets in which they have an interest are jointly owned.

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

Central Hudson: Primarily comprised of CH Energy Group, Inc. and Central Hudson Gas & Electric Corporation. Central Hudson is a regulated electric and gas transmission and distribution utility that serves portions of New York State's Mid-Hudson River Valley and owns gas-fired and hydroelectric generating capacity totalling 64 MW.

FortisBC Energy: Primarily comprised of FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, providing transmission and distribution services in over 135 communities. FortisBC Energy obtains natural gas supplies primarily from northeastern British Columbia and Alberta on behalf of most customers.

FortisAlberta: FortisAlberta Inc. is a regulated electricity distribution utility operating in a substantial portion of southern and central Alberta. It is not involved in the direct sale of electricity.

FortisBC Electric: Primarily comprised of FortisBC Inc., an integrated regulated electric utility operating in the southern interior of British Columbia. It owns four hydroelectric generating facilities with a combined capacity of 225 MW. It also provides operating, maintenance and management services relating to four hydroelectric generating facilities in British Columbia that are owned by third parties and to the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in which Fortis indirectly holds a 51% controlling interest (Notes 10 and 29).

Other Electric: Comprised of utilities in eastern Canada and the Caribbean, as follows: Newfoundland Power Inc. ("Newfoundland Power"); Maritime Electric Company, Limited ("Maritime Electric"); FortisOntario Inc. ("FortisOntario"); a 49% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Partnership") (Note 11); an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"); FortisTCI Limited and Turks and Caicos Utilities Limited (collectively "FortisTCI"); and a 33% equity investment in Belize Electricity Limited ("BEL") (Note 11).

In January 2019 Fortis reduced its equity investment in Wataynikaneyap Partnership from 49% to 39% to facilitate the inclusion of two additional First Nations communities into the partnership.

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador with a generating capacity of 139 MW, of which 97 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI") with on-Island generating capacity of 145 MW. FortisOntario is comprised of three regulated electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. Wataynikaneyap Partnership is a partnership between 24 First Nations communities and Fortis with a mandate of connecting remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines.

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 161 MW. FortisTCI is comprised of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a diesel-powered generating capacity of 91 MW. BEL is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

Energy Infrastructure: Primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generation assets in British Columbia include the Corporation's interest in the Waneta Expansion (Note 10), whose output is sold to British Columbia Hydro and Power Authority ("BC Hydro") and FortisBC Electric under 40-year power purchase agreements ("PPAs"). Generation 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 BEL under 50-year PPAs. Fortis indirectly owns 93.8% of Aitken Creek, with the remainder owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a working gas capacity of 77 billion cubic feet.

Corporate and Other: Captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments, including net corporate expenses of Fortis and the non-regulated holding company FortisBC Holdings Inc. ("FHI").

2. REGULATION

General

The earnings of the Corporation's regulated utilities are determined under cost of service ("COS") regulation, with some using performance-based rate setting ("PBR") mechanisms.

Under COS regulation the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of estimated costs of providing service, 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 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 achieving the forecasts established in the rate-setting process. Usage of a historical test year may cause regulatory lag between when costs are incurred and when they are reflected in customer rates.

When PBR mechanisms are utilized in determining customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements for a set term. PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

The Corporation's regulated utilities, where applicable, are permitted by their respective regulators 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 (Note 9).

ITC

ITC is regulated by the Federal Energy Regulatory Commission ("FERC") under the *Federal Power Act* (United States). Rates are set annually, using FERC-approved cost-based formula rate templates, and remain in effect for one year, which provides timely cost recovery. An annual true-up mechanism compares actual revenue requirements to billed revenues, and any variances are accrued and reflected in future rates within a two-year period. The formula rates do not require annual FERC approvals, although inputs remain subject to legal challenge by customers with FERC. ITC's rates reflect an allowed ROE ranging from 11.07% to 12.16% on a capital structure of 60% common equity for 2018 (ROE range of 11.32% to 12.16% and 60% common equity for 2017).

Incentive Adder Complaint
In April 2018 a third-party complaint was filed with FERC challenging the independence incentive adders that are included in transmission rates charged by transmission owners operating in the Midcontinent Independent System Operator ("MISO") region, which includes ITCTransmission, METC and ITC Midwest (collectively "ITC's MISO Subsidiaries"). The adder allowed up to 0.50% or 1.00% to be added to the authorized ROE, subject to any ROE cap established by FERC. In October 2018 FERC issued an order reducing the adders to 0.25%, effective April 20, 2018. This equates to a 0.25% decrease in ROE, down from the approximate 0.50% that ITC was earning in rates previously approved by FERC. ITC's MISO Subsidiaries sought rehearing of this order and began reflecting the 0.25% adder in transmission rates in November 2018. Refunds began in the fourth quarter of 2018 and were completed in the first quarter of 2019. The order is not expected to have a material impact on the Corporation's earnings or cash flows.

ROE Complaints
Two third-party complaints requested that the base ROE for MISO transmission owners, including ITC's MISO Subsidiaries, be found to no longer be just or reasonable. The complaints cover two consecutive 15-month periods from November 2013 through February 2015 (the "Initial Refund Period" or "Initial Complaint") and February 2015 through May 2016 (the "Second Refund Period" or "Second Complaint"). FERC orders on the complaints will also set the ROE that will be effective prospectively from the order dates.

In September 2016 FERC ordered that the base ROE for the Initial Refund Period be set at 10.32%, down from 12.38%, with a maximum of 11.35%. The resultant rates apply prospectively from September 2016 until an approved ROE is established for the Second Refund Period. The MISO transmission owners sought rehearing of this order. The total refund for the Initial Complaint as a result of the September 2016 FERC order was $158 million (US$118 million), including interest, and was paid in 2017 (Note 9).

In June 2016 the presiding Administrative Law Judge ("ALJ") issued an initial decision on the Second Complaint, recommending a base ROE of 9.70%, with a maximum of 10.68%. The initial decision of the ALJ is a non-binding recommendation to FERC, and FERC has yet to issue its order on the Second Complaint. In September 2017 certain MISO transmission owners filed a motion for FERC to dismiss the Second Complaint. Pending an order from FERC, an estimated regulatory liability of $206 million (US$151 million) has been recognized (December 31, 2017 - $182 million (US$145 million)) (Note 9).

There is uncertainty regarding the final outcome of the Initial and Second Complaints due in part to a November 2018 FERC order proposing a new methodology for determining a just and reasonable base ROE. If finalized, this proposed methodology will be used to address ITC's outstanding ROE complaints. Briefs are due to be filed in the first half of 2019 on the proposed adoption of the new methodology.

UNS Energy

UNS Energy is regulated by the Arizona Corporation Commission ("ACC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). UNS Energy uses a historical test year to establish retail electric and gas rates.

Effective February 27, 2017, TEP's rates reflect an allowed ROE of 9.75% on a capital structure of approximately 50% common equity, effective from July 1, 2013, prior to which its allowed ROE was 10.0% on a capital structure of 43.5% common equity. Effective August 1, 2016, UNS Electric's rates reflect an allowed ROE of 9.5% on a capital structure of 52.8% common equity. Effective May 1, 2012, UNS Gas' rates reflect an allowed ROE of 9.75% and a capital structure of 50.8% common equity.

Central Hudson

Central Hudson is regulated by the New York State Public Service Commission ("PSC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). Central Hudson uses a future test year to establish rates.

Effective July 1, 2018, pursuant to a three-year settlement agreement arising from a 2017 general rate application, Central Hudson's rates reflect an allowed ROE of 8.8% on a capital structure of 48%, 49% and 50% common equity in rate years one, two and three, respectively. Prior thereto, effective from July 1, 2015, Central Hudson's allowed ROE was 9.0% on a capital structure of 48% common equity.

Central Hudson is also subject to an earnings sharing mechanism whereby the Company and its customers share equally earnings between 50 and 100 basis points above the allowed ROE. Earnings beyond this are primarily returned to customers.

FortisBC Energy and FortisBC Electric

FortisBC Energy and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC") pursuant to the *Utilities Commission Act* (British Columbia), and are subject to multi-year PBR plans for 2014 through 2019 whereby a going-in revenue requirement is first established and used to set initial rates and thereafter a prescribed formula is applied annually to the previous year's rates to establish new rates for the remainder of the multi-year period.

The PBR plans incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FortisBC Energy and 1.03% for FortisBC Electric each year. The approved PBR plans also include a 50/50 sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FortisBC Energy and FortisBC Electric maintain specified service levels.

FortisBC Energy is the benchmark utility in British Columbia, as designated by the BCUC, and effective January 1, 2016, its rates reflect an allowed ROE of 8.75% and a capital structure of 38.5% common equity.

Effective January 1, 2016, FortisBC Electric's rates reflect an allowed ROE of 9.15% and a capital structure of 40% common equity.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). FortisAlberta is subject to multi-year PBR plans for 2013-2017 and 2018-2022 whereby a going-in revenue requirement is first established and used to set initial rates and thereafter a prescribed formula is applied annually to the previous year's rates to establish new rates for the remainder of the multi-year period.

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

Pursuant to generic cost of capital proceedings completed in 2018, FortisAlberta's rates reflect an allowed ROE of 8.5% on a capital structure of 37% common equity for 2018-2020, unchanged from 2017.

Other Electric

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities under the *Public Utilities Act* (Newfoundland and Labrador) and uses a future test year to establish rates. Effective 2016 to 2018, Newfoundland Power's rates reflect an allowed ROE of 8.5% on a capital structure of 45% common equity.

Maritime Electric is regulated by the Island Regulatory and Appeals Commission under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI) and the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), and uses a future test year to establish rates. Effective March 1, 2016 for a three-year period, Maritime Electric's rates reflect an allowed ROE of 9.35% on a capital structure of 40% common equity.

FortisOntario's three electric utilities are regulated by the Ontario Energy Board under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario). Two of FortisOntario's utilities use a future test year to establish rates under five-year PBR plans whereby a going-in revenue requirement is first established and used to set initial rates and thereafter a prescribed formula using inflationary factors less an efficiency target is applied annually to the previous year's rates to establish new rates for the remainder of the five-year period. The allowed ROEs ranged from 8.78% to 9.30% for both 2018 and 2017, on a capital structure of 40% common equity. FortisOntario's remaining utility is subject to a 35-year franchise agreement, expiring in 2033, whereby rates are based on a price cap with commodity cost flow through and with the base revenue requirement adjusted annually for inflation, load growth and customer growth.

Caribbean Utilities operates under licences from the Government of the Cayman Islands. Its exclusive transmission and distribution licence is for an initial period of 20 years, expiring in April 2028, with a provision for automatic renewal. Its non-exclusive generation licence is for a term of 25 years, expiring in November 2039. It is regulated under a rate-cap adjustment mechanism based on published consumer price indices. The licences detail the role of the Cayman Islands Utility Regulation and Competition Office, which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism, and annually approves capital expenditures. Its allowed ROA for 2018 was in the range of 7.00% to 9.00% (range of 6.75% to 8.75% for 2017).

FortisTCI operates under two 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037. Rates reflect a historical test year and a targeted allowed ROA of between 15.0% and 17.5% (the "Allowable Operating Profit"). The Allowable Operating Profit is based on a calculated rate base, including interest on the cumulative amount by which actual operating profits fall short of the Allowable Operating Profit (the "Cumulative Shortfall"). The calculated Allowable Operating Profit and Cumulative Shortfall are submitted to the Government annually. The recovery of the Cumulative Shortfall is dependent on future sales volumes and expenses. The achieved ROAs at the utilities have been significantly lower than those allowed as a result of the inability, due to economic and political factors, to increase rates to support significant capital investment in recent years.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These consolidated financial statements have been prepared and presented in accordance with accounting principles generally accepted in the United States of America ("US GAAP") for rate-regulated entities, and are in Canadian dollars unless otherwise indicated.

These consolidated financial statements include the accounts of the Corporation and its subsidiaries and controlled variable interest entity. They reflect the equity method of accounting for entities in which Fortis has significant influence, but not control, and proportionate consolidation for assets that are jointly owned with non-affiliated entities. Intercompany transactions have been eliminated, except for transactions between non-regulated and regulated entities in accordance with US GAAP for rate-regulated entities.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

Fortis and each subsidiary, other than ITC, maintains an allowance for doubtful accounts that is estimated based on a variety of factors, including receivables aging, historical experience, specific events such as customer bankruptcy and economic conditions. ITC recognizes losses for uncollectible accounts based upon their specific identification. Accounts receivable are written off in the period in which they are deemed uncollectible.

Inventories

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

Regulatory Assets and Liabilities

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

Certain remaining recovery and settlement periods are those expected by management and the actual periods could differ based on regulatory approval.

Investments

Investments accounted for using the equity method are reviewed annually for potential impairment in value. Impairments are recognized when identified.

Property, Plant and Equipment

Property, plant and equipment ("PPE") are recognized at cost less accumulated depreciation. Contributions in aid of construction by customers and governments are recognized as a reduction in the cost of, and are amortized in a manner consistent with, the related PPE.

Depreciation rates of the Corporation's regulated utilities include a provision for estimated future asset removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability (Note 9) against which actual asset removal costs are netted when incurred

Most of the Corporation's regulated utilities derecognize PPE on disposal or when no future economic benefits are expected from their use. Upon derecognition, any difference between cost and accumulated depreciation, net of salvage proceeds, is charged to accumulated depreciation. No gain or loss is recognized as it is expected that such amounts will be reflected in future depreciation expense when they are refunded or collected in customer rates.

Through methodologies established by their respective regulators, most of the Corporation's regulated utilities capitalize: (i) overhead costs that are not directly attributable to specific PPE but relate to the overall capital expenditure program; and (ii) an allowance for funds used during construction ("AFUDC").

The debt component of AFUDC totalling$31 million (2017 - $38 million) is reported as a reduction of finance charges and the equity component is reported as other income (Note 23). Both components are charged to earnings through depreciation expense over the estimated service lives of the applicable PPE.

At FortisAlberta the cost of PPE includes required contributions to the Alberta Electric System Operator ("AESO") toward funding the construction of transmission facilities.

Excluding UNS Energy, PPE includes inventory held for the development, construction and betterment of other assets. As required by its regulator, UNS Energy recognizes such items as inventory until used and reclassifies them to PPE once put into service.

Repairs and maintenance costs are charged to earnings in the period incurred. Replacements and betterments that extend the useful lives of PPE are capitalized.

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators. Depreciation rates for 2018 ranged from 0.9% to 34.6% (2017 - 0.9% to 34.6%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.5% for 2018 (2017 – 2.6%).

The service life ranges and weighted average remaining service life of the Corporation's PPE as at December 31 were as follows.

	2018		2017	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**33**	5-80	33
Gas	**14-95**	**35**	14-95	34
Transmission				
Electric	**20-90**	**42**	20-80	41
Gas	**5-85**	**41**	5-80	34
Generation	**1-85**	**24**	5-85	28
Other	**3-70**	**15**	3-70	14

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Capital leases are depreciated over the lease term, except where: (i) ownership of the asset is transferred at the end of the lease term, in which case depreciation is over the estimated service life of the underlying asset; and (ii) the regulator has approved a different recovery methodology for rate-setting purposes, in which case the timing of the expense recognition will conform to the regulator's requirements.

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

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Their useful lives are assessed to be either indefinite or finite.

Intangible assets with indefinite useful lives are not amortized and are tested for impairment annually, either individually or, where the particular entity also has goodwill, at the reporting unit level in conjunction with goodwill impairment testing. An annual review is completed to determine whether the indefinite life assessment continues to be supportable. If not, the resultant changes are made prospectively.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulators and ranged from 1.0% to 50.0% for 2018 (2017 – 1.0% to 50.0%).

The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows.

	2018		2017	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-10**	**4**	3-10	4
Land, transmission and water rights	**36-90**	**57**	36-80	57
Other	**10-100**	**13**	10-100	10

Most of the Corporation's regulated utilities derecognize intangible assets on disposal or when no future economic benefits are expected from their use. Upon derecognition any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization. No gain or loss is recognized as it is expected that such amounts will be reflected in future amortization costs when they are refunded or collected in customer rates.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of PPE, intangible assets with finite lives, and other long-term assets when events or changes in circumstances indicate that the carrying value may not exceed the total undiscounted cash flows expected to be generated by the asset. If that is determined to be the case, the asset is written down to estimated fair value and an impairment loss is recognized.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets related to business acquisitions.

Impairment testing is performed if an event or change in circumstances indicates that the fair value of a reporting unit may be below its carrying value. If that is determined to be the case, goodwill is written down to estimated fair value and an impairment loss is recognized.

Otherwise, Fortis performs an annual assessment for each of the 11 reporting units having goodwill. The primary method for estimating the fair value of 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 underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and 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, are also performed and compared to the results of the income approach.

Deferred Financing Costs

Issue costs, discounts and premiums are recognized against, and amortized over the life of, the related long-term debt.

Employee Future Benefits

Fortis and its subsidiaries each maintains one or a combination of defined benefit pension plans and defined contribution pension plans, as well as other post-employment benefit ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members.

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

For defined benefit pension plans and OPEB plans, the projected or accumulated benefit obligation and net benefit costs are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and, for OPEB plans, expected health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension or OPEB payments.

Defined benefit pension plan and OPEB plan assets are recognized at fair value. For the purpose of determining defined benefit pension cost, FortisBC Energy and Newfoundland Power use the market-related value whereby investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

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

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

For most of the Corporation's regulated utilities, any difference between defined benefit pension or OPEB plan costs ordinarily recognized under US GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates (Note 9).

For most of the Corporation's regulated utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension or OPEB plans, as applicable, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 9).

Stock-Based Compensation

Compensation expense related to stock options is measured at the grant date using the Black-Scholes fair value option-pricing model and each grant is amortized to compensation expense as a single award evenly over the four-year vesting period, with the offsetting entry to additional paid-in capital.

Fortis satisfies stock option exercises by issuing common shares from treasury. Upon exercise, proceeds are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock.

Fortis recognizes liabilities associated with its Directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans, all representing cash-settled awards, at fair value at each reporting date until settlement. The fair value of these liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP as at December 31, 2018 was $45.14 (December 31, 2017 - $46.01). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

Compensation expense is recognized on a straight-line basis over the vesting period, which for the PSU and RSU Plans is over the lesser of three years or the period to retirement eligibility and for the DSU Plan is at the time of grant. Forfeitures are accounted for as they occur.

Foreign Currency Translation

Assets and liabilities of the Corporation's foreign operations, all of which have a US dollar functional currency, are translated at the exchange rate in effect at the balance sheet date and the resultant unrealized translation gains and losses are recognized in accumulated other comprehensive income. The exchange rate as at December 31, 2018 was US$1.00=CAD$1.36 (December 31, 2017 – US$1.00=CAD$1.25).

Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate for the reporting period, which was US$1.00=CAD$1.30 for 2018 (2017 - US$1.00=CAD$1.30).

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

Translation gains and losses on foreign currency-denominated debt that is designated as an effective hedge of foreign net investments are recognized in other comprehensive income.

Derivatives and Hedging

Derivatives Not Designated as Hedges
Derivatives not designated as hedges are used by: (i) Fortis, to manage cash flow risk associated with forecast US dollar cash inflows and forecast future cash settlements of DSU and RSU obligations; (ii) UNS Energy, to meet forecast load and reserve requirements; and (iii) Aitken Creek, to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions. These derivatives are measured at fair value with changes thereto recognized in earnings.

Derivatives not designated as hedges are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These derivatives are measured at fair value with changes thereto recognized as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 9).

Derivatives that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized in earnings as energy supply costs.

Derivatives Designated as Hedges
The Corporation, ITC and UNS Energy use cash flow hedges to manage interest rate risk. Unrealized gains and losses are initially recognized in accumulated other comprehensive income and reclassified to earnings when the underlying hedged transaction affects earnings. Any hedge ineffectiveness is immediately recognized in earnings.

The Corporation's earnings from, and net investments in, foreign subsidiaries and equity-accounted investments are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has hedged a portion of this exposure through US dollar-denominated debt at the corporate level. Exchange rate fluctuations associated with the translation of this debt and the foreign net investments are recognized in accumulated other comprehensive income.

Presentation of Derivatives
The fair values of derivatives are recognized as current or long-term assets and liabilities depending on the timing of settlements and resulting cash flows. Derivatives under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivatives are presented in operating activities in the consolidated statements of cash flows.

Income Taxes

The Corporation and its taxable subsidiaries follow the asset and liability method of accounting for income taxes. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

Deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not to be realized. They are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period when the change occurs. Valuation allowances are recognized when it is more likely than not that all, or a portion of, a deferred income tax asset will not be realized.

Customer rates at ITC, UNS Energy, Central Hudson and Maritime Electric reflect current and deferred income tax. Customer rates at FortisAlberta reflect current income tax. Customer rates at FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario reflect current income tax and, for certain regulatory balances, deferred income tax. Caribbean Utilities, FortisTCI and, for the 50-year term of its power purchase agreements, BECOL are not subject to income tax.

Differences between the income tax expense or recovery recognized under US GAAP and that reflected in current customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities (Note 9).

At FortisAlberta the capital cost allowance pool for certain PPE for rate-setting purposes is different from that prescribed for Canadian tax filing purposes. In a future reporting period yet to be determined, the difference may result in reported income tax expense exceeding that reflected in customer rates.

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $2.3 billion as at December 31, 2018 (December 31, 2017 - $561 million). If such earnings are repatriated, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

Tax benefits associated with actual or expected income tax positions are recognized when the "more likely than not" recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement.

Income tax interest and penalties are recognized as income tax expense when incurred.

Asset Retirement Obligations

The Corporation's subsidiaries have asset retirement obligations ("AROs") associated with certain generation, transmission, distribution and interconnection assets, including land and environmental remediation and/or asset removal. These assets and related licences, permits, right-of-ways and agreements are reasonably expected to effectively exist and operate in perpetuity due to their nature. Consequently, where the final date and cost of remediation and/or removal of the noted assets cannot be reasonably determined, AROs have not been recognized.

Otherwise, AROs are recognized at fair value in the period incurred as an increase in PPE and long-term other liabilities (Note 18) if a reasonable estimate of fair value can be determined. Fair value is estimated as the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recognized through accretion and the capitalized cost is depreciated over the useful life of the asset. Actual settlement costs are recognized as a reduction in the accrued liability.

Contingencies

Fortis and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. Management makes judgments regarding the future outcome of contingent events and recognizes a loss based on its best estimate when it is determined that such loss, or range of loss, is probable and can be reasonably estimated. Legal fees are expensed as incurred. When a loss is recoverable in future rates, a regulatory asset is also recognized.

Management regularly reviews current information to determine whether recognized provisions should be adjusted and new provisions are required. However, estimating probable losses requires considerable judgment about potential actions by third parties and matters are often resolved over long time periods. Actual outcomes may differ materially from the amounts recognized.

New Accounting Policies

Revenue Recognition
Effective January 1, 2018, Fortis adopted Accounting Standards Codification ("ASC") 606,*Revenue from Contracts with Customers*, which clarifies the principles for recognizing revenue and requires additional disclosures (Note 6). Fortis adopted this standard using the modified retrospective approach, under which comparative periods are not restated and the cumulative impact is recognized at the date of adoption, supplemented by additional disclosures. Upon adoption, there were no adjustments to the opening balance of retained earnings.

Most revenue is derived from energy sales and the provision of transmission services to customers based on regulator-approved tariff rates. Most contracts have a single performance obligation, being the delivery of energy or the provision of transmission services. No component of the transaction price is allocated to unsatisfied performance obligations. Revenue is generally measured in kilowatt hours, gigajoules or transmission load delivered. The billing of energy sales is based on customer meter readings, which occur systematically throughout each month. The billing of transmission services at ITC is based on peak monthly load.

FortisAlberta is a distribution company and is required by its regulator to arrange and pay for transmission services with the AESO. This includes the collection of transmission revenue from its customers, which occurs through the transmission component of its regulator-approved rates. FortisAlberta reports transmission revenue and expenses on a net basis.

Electricity, gas and transmission service revenue includes an estimate for unbilled energy consumed or service provided since the last meter reading that has not been billed at the end of the reporting period. Sales estimates generally reflect an analysis of historical consumption in relation to key inputs, such as current energy prices, population growth, economic activity, weather conditions and system losses. Unbilled revenue accruals are adjusted in the periods actual consumption becomes known.

Generation revenue from non-regulated operations is recognized on delivery at contracted fixed or market rates.

Variable consideration is estimated at the most likely amount and reassessed at each reporting date until the amount is known. Variable consideration, including amounts subject to a future regulatory decision, is recognized as a refund liability until entitlement is certain.

Revenue excludes sales and municipal taxes collected from customers. Prior to the adoption of ASC 606, Central Hudson recognized sales tax and FortisAlberta recognized municipal tax on a gross basis in both revenue and expense. The exclusion of these taxes from revenue resulted in a decrease in revenue of $49 million for 2018 compared to 2017.

The Corporation has elected not to assess or account for any significant financing components associated with revenue billed in accordance with equal payment plans as the period between the transfer of energy to customers and the customers' payment will be less than one year.

Revenue is disaggregated by geography, regulatory status, and substantially autonomous utility operations (Note 5). This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer ("CEO") to allocate resources and evaluate performance.

Financial Instruments
Effective January 1, 2018, the Corporation adopted Accounting Standards Update ("ASU") No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*. Principally, it requires: (i) equity investments in unconsolidated entities not accounted for using the equity method to be measured at fair value through earnings; however, entities may 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 liabilities to be presented separately in the financial statement notes, grouped by measurement category and form. Adoption did not impact these consolidated financial statements.

Pension and Post-Retirement Benefit Costs
Effective January 1, 2018, the Corporation adopted ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost*, which requires current service costs to be grouped in the statement of earnings with other employee compensation costs arising from services rendered. The remaining components of net periodic benefit costs must be presented separately and outside of operating income. Additionally, only the service cost component can be capitalized. On adoption, the Corporation applied the presentation guidance retrospectively and the capitalization guidance prospectively. This resulted in a retrospective $11 million reclassification from Operating Expenses to Other Income, Net in the consolidated financial statements.

Use of Accounting Estimates

The preparation of these consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments, including those arising from matters dependent upon the finalization of regulatory proceedings, that affect the reported amounts of assets, liabilities, revenues, expenses, gains and losses. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments being recognized in the period they become known. Actual results may differ significantly from these estimates.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

Leases

ASU No. 2016-02, *Leases* ("ASC 842"), issued in February 2016, is effective for Fortis January 1, 2019 and is to be applied using a modified retrospective approach or an optional transition method with implementation options, referred to as practical expedients. Principally, it requires balance sheet recognition of a right-of-use asset and a lease liability by lessees for those leases that are classified as operating leases, along with additional disclosures.

Fortis has selected the optional transition method, which allows entities to continue to apply the current lease guidance in the comparative periods presented in the year of adoption and apply the transition provisions of the new guidance on the effective date of the new guidance. Fortis elected a package of practical expedients that allowed it to not reassess the lease classification of existing leases or whether existing contracts, including land easements, are or contain a lease. Finally, Fortis utilized the hindsight practical expedient to determine the lease term.

Upon adoption, Fortis will recognize right-of-use assets and corresponding lease liabilities of approximately$50 million for operating leases primarily related to office facilities and utility property. Operating leases related to vehicles and office equipment were identified and quantified as immaterial. Fortis has not identified an adjustment to opening retained earnings, and there will be no impact on earnings or cash flows.

Fortis implemented changes to processes and control activities related to monitoring the adoption of ASC 842 and made changes to accounting policies associated with accounting for lease assets and liabilities, and related income and expense, as of January 1, 2019.

Financial Instruments

ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, issued in June 2016, is effective for Fortis January 1, 2020 and is to be applied on a modified retrospective basis. Principally, it requires entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to estimate credit losses. The adoption of this ASU will not have a material impact on the consolidated financial statements and related disclosures.

Hedging

ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, issued in August 2017, is effective for Fortis January 1, 2019. Principally, it better aligns risk management activities and financial reporting for hedging relationships through changes to designation, measurement, presentation and disclosure guidance. For cash flow and net investment hedges that existed at the date of adoption, the amendments were applied as a cumulative-effect adjustment related to eliminating the separate measurement of ineffectiveness to accumulated other comprehensive income with a corresponding adjustment to opening retained earnings. Amended presentation and disclosure guidance was applied prospectively. The adoption of this ASU will not have a material impact on the consolidated financial statements and related disclosures.

Fair Value Measurement Disclosures

ASU No. 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement,* issued in August 2018, is effective for Fortis January 1, 2020 and is to be primarily applied on a retrospective basis, with certain disclosures requiring prospective application. Principally, it improves the effectiveness of financial statement note disclosures by clarifying what is required and important to users of the financial statements. In addition, the amendment removes (a) the amount of, and reasons for, transfers between level 2 and level 3 of the fair value hierarchy, (b) the policy for timing of transfers between levels, and (c) the valuation processes for level 3 fair value measurements. Fortis does not expect the adoption of this ASU to have a material impact on the related disclosures.

Pensions and Other Post-Retirement Plan Disclosures

ASU No. 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans*, issued in August 2018, is effective for Fortis January 1, 2021 and is to be applied on a retrospective basis for all periods presented. Principally, it modifies the disclosure requirements for employers with defined pension or other post-retirement plans and clarifies disclosure requirements. In addition, the amendments remove (a) the amounts in accumulated other comprehensive income expected to be recognized as components of net period benefit costs over the next fiscal period, (b) the amount and timing of plan assets expected to be returned to the employer, and (c) the effects of a one-percentage-point change on the assumed health care costs and the change in rates on service cost, interest cost and the benefit obligation for post-retirement health care benefits. Fortis does not expect the adoption of this ASU to have a material impact on the related disclosure.

5. SEGMENTED INFORMATION

General

Fortis segments its business based on regulatory status and service territory, as well as the information used by its President and CEO in deciding how to allocate resources. The performance of each segment is primarily based on net earnings attributable to common equity shareholders.

Effective January 1, 2018, the former Eastern Canadian and Caribbean segments were aggregated as Other Electric as they individually do not meet the quantitative threshold for separate reporting.

Related-party and inter-company transactions

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2018 or 2017.

Inter-company balances, transactions and 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. Inter-company transactions are summarized below.

(in millions)	**2018**	2017
Sale of capacity from Waneta Expansion to FortisBC Electric	**$ 47**	$ 46
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**25**	24

As at December 31, 2018, accounts receivable included approximately $16 million due from BEL (December 31, 2017 - $20 million).

The Corporation periodically provides short-term financing to subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements. There were no material inter-segment loans outstanding as at December 31, 2018 and 2017.

	REGULATED								NON-REGULATED			
Year Ended December 31, 2018 *(in millions)*	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Sub total**	**Energy Infra-structure**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Revenue	$1,504	$2,202	$ 924	$ 1,187	$ 579	$ 408	$ 1,412	**$ 8,216**	**$ 184**	**$ —**	**$ (10)**	**$ 8,390**
Energy supply costs	—	868	315	322	—	135	853	**2,493**	**2**	**—**	**—**	**2,495**
Operating expenses	448	609	410	308	167	105	182	**2,229**	**40**	**28**	**(10)**	**2,287**
Depreciation and amortization	234	272	71	219	192	61	160	**1,209**	**32**	**2**	**—**	**1,243**
Operating income	822	453	128	338	220	107	217	**2,285**	**110**	**(30)**	**—**	**2,365**
Other income, net	40	10	7	7	1	3	1	**69**	**1**	**(10)**	**—**	**60**
Finance charges	285	104	41	134	100	40	76	**780**	**6**	**188**	**—**	**974**
Income tax expense	139	66	20	55	1	14	22	**317**	**6**	**(158)**	**—**	**165**
Net earnings	438	293	74	156	120	56	120	**1,257**	**99**	**(70)**	**—**	**1,286**
Non-controlling interests	77	—	—	1	—	—	15	**93**	**27**	**—**	**—**	**120**
Preference share dividends	—	—	—	—	—	—	—	**—**	**—**	**66**	**—**	**66**
Net earnings attributable to common equity shareholders	$ 361	$ 293	$ 74	$ 155	$ 120	$ 56	$ 105	**$ 1,164**	**$ 72**	**$ (136)**	**$ —**	**$ 1,100**
Goodwill	$8,369	$1,884	$ 615	$ 913	$ 227	$ 235	$ 260	**$ 12,503**	**$ 27**	**$ —**	**$ —**	**$ 12,530**
Total assets	19,798	10,182	3,670	6,815	4,691	2,244	4,119	**51,519**	**1,478**	**127**	**(73)**	**53,051**
Capital expenditures	998	599	245	486	433	106	300	**3,167**	**44**	**7**	**—**	**3,218**

Year Ended December 31, 2017 *(in millions)*												
Revenue	$1,575	$2,080	$ 872	$ 1,198	$ 600	$ 398	$ 1,363	$ 8,086	$ 226	$ 1	$ (12)	$ 8,301
Energy supply costs	—	711	260	411	—	142	836	2,360	2	—	(1)	2,361
Operating expenses	433	609	399	300	198	90	171	2,200	49	12	(11)	2,250
Depreciation and amortization	220	260	65	198	190	62	150	1,145	32	2	—	1,179
Operating income	922	500	148	289	212	104	206	2,381	143	(13)	—	2,511
Other income, net	37	19	5	22	2	2	1	88	1	28	(1)	116
Finance charges	259	101	41	116	93	37	74	721	5	189	(1)	914
Income tax expense	371	148	42	40	1	14	22	638	19	(69)	—	588
Net earnings	329	270	70	155	120	55	111	1,110	120	(105)	—	1,125
Non-controlling interests	57	—	—	1	—	—	13	71	26	—	—	97
Preference share dividends	—	—	—	—	—	—	—	—	—	65	—	65
Net earnings attributable to common equity shareholders	$ 272	$ 270	$ 70	$ 154	$ 120	$ 55	$ 98	$ 1,039	$ 94	$ (170)	$ —	$ 963
Goodwill	$7,698	$1,733	$ 566	$ 913	$ 227	$ 235	$ 245	$ 11,617	$ 27	$ —	$ —	$ 11,644
Total assets	17,581	8,596	3,188	6,418	4,454	2,197	3,814	46,248	1,605	76	(107)	47,822
Capital expenditures	982	534	220	446	414	105	302	3,003	21	—	—	3,024

6. REVENUE

(in millions)	**2018**	2017
Electric and gas revenue		
United States		
ITC	**$ 1,539**	$ 1,583
UNS Energy	**1,993**	1,875
Central Hudson	**963**	814
Canada		
FortisBC Energy	**1,136**	1,244
FortisAlberta	**554**	593
FortisBC Electric	**354**	347
Newfoundland Power	**651**	666
Maritime Electric	**200**	191
FortisOntario	**197**	197
Caribbean		
Caribbean Utilities	**253**	222
FortisTCI	**78**	71
Total electric and gas revenue	**7,918**	7,803
Other services revenue *(1)*	**408**	395
Revenue from contracts with customers	**8,326**	8,198
Alternative revenue	**16**	(46)
Other revenue	**48**	149
Total revenue	**$ 8,390**	$ 8,301

(1) Includes $234 million and $217 million from regulated operations for 2018 and 2017, respectively

Revenue from Contracts with Customers
Electric and gas revenue includes revenue from the sale and/or delivery of electricity and gas, transmission revenue, and wholesale electric revenue, all based on regulator-approved tariff rates.

Other services revenue includes: (i) the sale of energy from non-regulated generation operations; (ii) management fee revenue at UNS Energy for the operation of Springerville Units 3 and 4; (iii) revenue from storage optimization activities at Aitken Creek; and (iv) revenue from other services that reflect the ordinary business activities of Fortis' utilities.

Alternative Revenue
Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria are met. Alternative revenue is recognized on an accrual basis with a corresponding regulatory asset or liability until the revenue is settled. Upon settlement, revenue is not recognized as revenue from contracts with customers but rather as settlement of the regulatory asset or liability on the balance sheet. The Corporation's significant alternative revenue programs are summarized as follows.

ITC's formula rates include an annual true-up mechanism that compares actual revenue requirements to billed revenue, and any under- or over-collections are accrued as a regulatory asset or liability and reflected in future rates within a two-year period (Note 9). The formula rates do not require annual regulatory approvals, although inputs remain subject to legal challenge.

UNS Energy's lost fixed-cost recovery mechanism ("LFCR") surcharge recovers lost fixed costs, as measured by a reduction in non-fuel revenue, associated with energy efficiency savings and distributed generation. To recover the LFCR regulatory asset, UNS Energy is required to file an annual LFCR adjustment request with the ACC for the LFCR revenue recognized in the prior year. The recovery is subject to a year-over-year cap of 1% of total retail revenue. UNS Energy's demand side management surcharge, which is approved by the ACC annually, compensates for the costs to design and implement cost-effective energy efficiency and demand response programs until such costs, along with a performance incentive, are reflected in non-fuel base rates.

At FortisBC Energy and FortisBC Electric, the earnings sharing mechanism allows for a50/50 sharing of variances from operating and maintenance expenses and capital expenditures approved as part of the annual revenue requirements. This mechanism is in place until the expiry of the current PBR plan in 2019. Additionally, variances in the forecast versus actual customer-use rate are captured throughout the year in a revenue stabilization adjustment mechanism and a flow-through deferral account, both of which are either refunded to, or recovered from, customers in rates within two years.

Other Revenue
Other revenue primarily includes gains or losses on energy contract derivatives and lease revenue.

7. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	**2018**	2017
Trade accounts receivable	**$ 538**	$ 460
Unbilled accounts receivable	**575**	562
Allowance for doubtful accounts	**(33)**	(31)
Total accounts receivable	**1,080**	991
Income tax receivable	**91**	8
Other *(1)*	**186**	132
	$ 1,357	$ 1,131

(1) Consists of customer billings for non-core services, gas mitigation costs and collateral deposits for gas purchases at FortisBC Energy, and the fair value of derivative instruments (Note 28)

8. INVENTORIES

(in millions)	**2018**	2017
Materials and supplies	**$ 280**	$ 238
Gas and fuel in storage	**87**	97
Coal inventory	**31**	32
	$ 398	$ 367

9. REGULATORY ASSETS AND LIABILITIES

(in millions)	2018	2017
Regulatory assets		
Deferred income taxes (Notes 3 and 24)	**$ 1,532**	$ 1,403
Employee future benefits (Notes 3 and 25)	**485**	510
Deferred energy management costs *(i)*	**230**	200
Deferred lease costs *(ii)*	**110**	104
Deferred operating overhead costs *(iii)*	**103**	91
Generation early retirement costs *(iv)*	**98**	105
Rate stabilization and related accounts *(v)*	**90**	95
Manufactured gas plant site remediation deferral (Note 18)	**73**	75
Derivatives (Notes 3 and 28)	**57**	87
Other regulatory assets *(vi)*	**400**	375
Total regulatory assets	**3,178**	3,045
Less: Current portion	**(324)**	(303)
Long-term regulatory assets	**$ 2,854**	$ 2,742
Regulatory liabilities		
Deferred income taxes (Notes 3 and 24)	**$ 1,574**	$ 1,484
Asset removal cost provision (Note 3)	**1,169**	1,095
Rate stabilization and related accounts *(v)*	**220**	254
ROE complaints liability (Note 2)	**206**	182
Energy efficiency liability *(vii)*	**106**	82
Renewable energy surcharge *(viii)*	**85**	66
Electric and gas moderator account *(ix)*	**60**	58
Employee future benefits (Notes 3 and 25)	**37**	47
Other regulatory liabilities *(vi)*	**169**	178
Total regulatory liabilities	**3,626**	3,446
Less: Current portion	**(656)**	(490)
Long-term regulatory liabilities	**$ 2,970**	$ 2,956

(i) Deferred Energy Management Costs
Certain regulated subsidiaries provide energy management services to facilitate customer energy efficiency programs where the related expenditures have been deferred as a regulatory asset and are being amortized, and recovered from customers through rates, on a straight-line basis over periods ranging from 1 to 10 years.

(ii) Deferred Lease Costs
Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA") (Note 17). The depreciation of the asset under capital lease and interest expense on the capital lease obligation are not being fully recovered in current customer rates since these rates only reflect the cash payments required under BPPA. The annual differences are being deferred as a regulatory asset, which is expected to be recovered from customers in future rates over the term of the lease, which expires in 2056.

(iii) Deferred Operating Overhead Costs
FortisAlberta has deferred certain operating overhead costs for collection in future customer rates over the lives of the related PPE and intangible assets.

(iv) Generation Early Retirement Costs

UNS Energy holds an undivided interest in the jointly-owned Navajo Generating Station ("Navajo"), located on a site leased from the Navajo Nation with an initial lease term through December 2019. In June 2017 the Navajo Nation approved a land-lease extension that allows TEP and the co-owners of Navajo to continue operations through December 2019 and begin decommissioning activities thereafter. Related retirement costs are being recovered through 2030.

UNS Energy owns the Sundt Generating Facility ("Sundt") and plans to early retire Sundt Units 1 and 2 by the end of 2020 as a result of the approved addition of gas-fired generation capacity at Sundt. Capital and operating costs related to Sundt Units 1 and 2 are being recovered through 2028 and 2030, respectively.

As a result of these planned early retirements, the associated assets and other related retirement costs were reclassified from PPE to regulatory assets.

(v) Rate Stabilization and Related Accounts

Rate stabilization accounts mitigate the earnings volatility otherwise caused by variability in the cost of fuel, purchased power and natural gas above or below a forecast or predetermined level, and by weather-driven volume variability. At certain utilities, revenue decoupling mechanisms minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented. Resultant deferrals are recovered from, or refunded to, customers in future rates as approved by the respective regulators.

Related accounts include the annual true-up mechanism at ITC (Note 6).

(vi) Other Regulatory Assets and Liabilities

This balance is comprised of regulatory assets and liabilities individually less than $40 million.

(vii) Energy Efficiency Liability

The energy efficiency liability primarily relates to Central Hudson's Energy Efficiency Program, established to fund environmental policies associated with energy conservation programs as approved by its regulator.

(viii) Renewable Energy Surcharge

Under the ACC's Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements by 2025. The cost of carrying out the plan is recovered from retail customers through an RES surcharge. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory liability or asset.

The ACC measures RES compliance through Renewable Energy Credits ("REC"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records their cost as long-term other assets (Note 11) with a corresponding regulatory liability to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, energy supply costs and revenue are recognized in an equal amount.

(ix) Electric and Gas Moderator Account

Under Central Hudson's 2018 three-year Rate Order certain regulatory assets and liabilities were approved by the PSC for offset and an electric and gas moderator account was established, which will be used for future customer rate moderation.

Regulatory assets not earning a return: (i) totalled $1,490 million and $1,464 million as at December 31, 2018 and 2017, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

10. ASSETS HELD FOR SALE

In 2018 Fortis solicited offers to sell its51% ownership interest in the Waneta Expansion. In January 2019 the Corporation entered into a definitive agreement with Columbia Power Corporation ("CPC") and Columbia Basin Trust ("CBT") to sell its interest for approximately $1 billion. CPC and CBT, both 100% owned by the Government of British Columbia, are the Corporation's partners and together currently own 49% of the Waneta Expansion. Fortis expects the transaction to close in the second quarter of 2019 following the satisfaction of customary closing conditions. FortisBC Electric will continue to operate the Waneta Expansion facility and purchase its surplus capacity. The related assets and liabilities have been classified as held for sale and are detailed below.

(in millions)		**2018**
Cash	**$**	**15**
Accounts receivable and other current assets		**3**
PPE		**718**
Intangible assets		**30**
Total assets held for sale	**$**	**766**
Accounts payable and other current liabilities	**$**	**2**
Other liabilities		**67**
Total liabilities associated with assets held for sale	**$**	**69**

The non-controlling interest of $324 million remained classified in equity.

For both 2018 and 2017, the Waneta Expansion contributed$54 million to earnings before income tax expense, of which51% is attributable to common equity shareholders.

11. OTHER ASSETS

(in millions)		**2018**		2017
Supplemental Executive Retirement Plan	**$**	**143**	$	130
Renewable Energy Credits (Note 9 *(viii)*)		**88**		62
Equity investment - BEL		**76**		73
Equity investment - Wataynikaneyap Partnership		**43**		22
Other investments		**34**		29
Defined benefit pension plan (Note 25)		**26**		31
Deferred compensation plan		**26**		24
Other *(1)*		**116**		109
	$	**552**	$	480

(1) Other assets are generally recorded at cost and recovered or amortized over the estimated period of future benefit, where applicable. Other assets also include the fair value of derivatives (Note 28).

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through Supplemental Executive Retirement Plans ("SERPs") and deferred compensation plans for Directors and Officers. The assets held to support these plans are reported separately from the related liabilities (Note 18). Most plan assets are held in trust and funded mainly through trust-owned life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 28). Included in SERP assets are available-for-sale securities at ITC of$72 million (2017 - $66 million), for which gains and losses are recognized in earnings.

12. PROPERTY, PLANT AND EQUIPMENT

(in millions)	Cost	Accumulated Depreciation	Net Book Value
2018			
Distribution			
Electric	**$ 10,880**	**$ (3,076)**	**$ 7,804**
Gas	**4,767**	**(1,244)**	**3,523**
Transmission			
Electric	**14,665**	**(3,212)**	**11,453**
Gas	**2,214**	**(639)**	**1,575**
Generation	**6,164**	**(2,279)**	**3,885**
Other	**3,877**	**(1,251)**	**2,626**
Assets under construction	**1,478**	**—**	**1,478**
Land	**310**	**—**	**310**
	$ 44,355	**$ (11,701)**	**$ 32,654**
2017			
Distribution			
Electric	$ 9,963	$ (2,864)	$ 7,099
Gas	4,093	(1,157)	2,936
Transmission			
Electric	12,571	(2,838)	9,733
Gas	1,954	(596)	1,358
Generation	6,079	(1,996)	4,083
Other	3,608	(1,130)	2,478
Assets under construction	1,717	—	1,717
Land	264	—	264
	$ 40,249	$ (10,581)	$ 29,668

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kilovolts ("kV")). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kilopascals ("kPa")) or a hoop stress of less than 20% of standard minimum yield strength. These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher) or a hoop stress of 20% or more of standard minimum yield strength. These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems and other related equipment.

Other assets include buildings, equipment, vehicles, inventory, information technology assets and the Aitken Creek natural gas storage facility.

As at December 31, 2018, assets under construction were primarily associated with ongoing transmission projects at ITC and the addition of gas-fired generation capacity at UNS Energy.

The cost of PPE under capital lease as at December 31, 2018 was $656 million (December 31, 2017 -$423 million) and related accumulated depreciation was $203 million (December 31, 2017 - $176 million).

Jointly-Owned Facilities

UNS Energy and ITC hold undivided interests in jointly-owned generating facilities and transmission systems, are entitled to their pro rata share of the PPE, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2018, interests in jointly-owned facilities consisted of the following.

(in millions, except as noted)	Ownership %	Cost	Accumulated Depreciation	Net Book Value
San Juan Unit 1	50.0	$ 397	$ (183)	$ 214
Four Corners Units 4 and 5	7.0	239	(104)	135
Luna Energy Facility	33.3	79	(5)	74
Gila River Common Facilities	25.0	45	(16)	29
Springerville Coal Handling Facilities	83.0	284	(117)	167
Transmission Facilities	1.0-80.0	1,018	(397)	621
		$ 2,062	$ (822)	$ 1,240

13. INTANGIBLE ASSETS

(in millions)	Cost	Accumulated Amortization	Net Book Value
2018			
Computer software	$ 860	$ (533)	$ 327
Land, transmission and water rights	855	(125)	730
Other	120	(58)	62
Assets under construction	81	—	81
	$ 1,916	$ (716)	$ 1,200
2017			
Computer software	$ 784	$ (474)	$ 310
Land, transmission and water rights	743	(103)	640
Other	117	(49)	68
Assets under construction	63	—	63
	$ 1,707	$ (626)	$ 1,081

Included in the cost of land, transmission and water rights as at December 31, 2018 was $131 million (December 31, 2017 - $150 million) not subject to amortization. Amortization expense was $106 million for 2018 (2017 - $97 million). Amortization is estimated to average approximately $81 million for each of the next five years.

14. GOODWILL

(in millions)	**2018**	2017
Balance, beginning of year	**$ 11,644**	$ 12,364
Acquisition of ITC	**—**	(6)
Foreign currency translation impacts *(1)*	**886**	(714)
Balance, end of year	**$ 12,530**	$ 11,644

(1) Relates to the translation of goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and FortisTCI, whose functional currency is the US dollar

No goodwill impairment was recognized by the Corporation in2018 or 2017.

15. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)	**2018**	2017
Trade accounts payable	**$ 679**	$ 696
Gas and fuel cost payable	**281**	146
Customer and other deposits	**267**	204
Interest payable	**230**	223
Accrued taxes other than income taxes	**206**	178
Dividends payable	**199**	185
Employee compensation and benefits payable	**193**	184
Fair value of derivatives (Note 28)	**69**	71
Manufactured gas plant site remediation (Note 18)	**32**	35
Defined benefit pension and OPEB liabilities (Note 25)	**25**	22
Other	**108**	109
	$ 2,289	$ 2,053

16. LONG-TERM DEBT

(in millions)	Maturity Date	**2018**	2017
ITC			
Secured US First Mortgage Bonds -			
4.51% weighted average fixed rate (2017 - 4.67%)	2020-2055	**$ 2,652**	$ 2,063
Secured US Senior Notes -			
4.19% weighted average fixed rate (2017 - 4.19%)	2040-2046	**648**	596
Unsecured US Senior Notes -			
3.91% weighted average fixed rate (2017 - 3.91%)	2020-2043	**3,751**	3,451
Unsecured US Shareholder Note -			
6.00% fixed rate (2017 - 6.00%)	2028	**271**	250
Unsecured US Term Loan Credit Agreement -			
2.03% weighted average variable rate	n/a	**—**	63
UNS Energy			
Unsecured US Tax-Exempt Bonds - 4.66% weighted			
average fixed and variable rate (2017 - 4.04%)	2020-2040	**654**	773
Unsecured US Fixed Rate Notes -			
4.38% weighted average fixed rate (2017 - 4.26%)	2021-2048	**1,943**	1,411
Central Hudson			
Unsecured US Promissory Notes - 4.43% weighted			
average fixed and variable rate (2017 - 4.28%)	2019-2057	**938**	770
FortisBC Energy			
Unsecured Debentures -			
5.03% weighted average fixed rate (2017 - 5.13%)	2026-2048	**2,595**	2,395
FortisAlberta			
Unsecured Debentures -			
4.64% weighted average fixed rate (2017 - 4.70%)	2024-2052	**2,185**	2,035
FortisBC Electric			
Secured Debentures -			
8.80% fixed rate (2017 - 8.80%)	2023	**25**	25
Unsecured Debentures -			
5.05% weighted average fixed rate (2017 - 5.05%)	2021-2050	**710**	710
Other Electric			
Secured First Mortgage Sinking Fund Bonds -			
6.14% weighted average fixed rate (2017 - 6.14%)	2020-2057	**578**	585
Secured First Mortgage Bonds -			
5.66% weighted average fixed rate (2017 - 6.19%)	2025-2061	**220**	195
Unsecured Senior Notes -			
4.45% weighted average fixed rate (2017 - 6.11%)	2041-2048	**152**	104
Unsecured US Senior Loan Notes and Bonds - 4.76% weighted			
average fixed and variable rate (2017 - 4.80%)	2020-2048	**584**	525
Corporate			
Unsecured US Senior Notes and Promissory Notes -			
3.41% weighted average fixed rate (2017 - 3.41%)	2019-2044	**4,398**	4,046
Unsecured Debentures -			
6.50% weighted average fixed rate (2017 - 6.50%)	2039	**200**	200
Unsecured Senior Notes - 2.85% fixed rate (2017 - 2.85%)	2023	**500**	500
Long-term classification of credit facility borrowings		**1,066**	671
Fair value adjustment - ITC acquisition		**161**	167
Total long-term debt (Note 28)		**24,231**	21,535
Less: Deferred financing costs and debt discounts		**(146)**	(139)
Less: Current installments of long-term debt		**(926)**	(705)
		$ 23,159	$ 20,691

Most long-term debt at the Corporation's regulated utilities is redeemable at the option of the respective utility at the greater of par or a specified price, together with accrued and unpaid interest. Security, if provided, is typically through a fixed or floating first charge on specific assets of the utility.

The Corporation's unsecured debentures and senior notes are redeemable at the option of Fortis at the greater of par or a specified price together with accrued and unpaid interest.

Certain long-term debt at the Corporation has covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure.

One long-term debt obligation at the Corporation has a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, make any other distribution on its shares, redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would exceed 75% of its total consolidated capitalization.

Long-Term Debt Issuances

(in millions, except %)	**Month Issued**	**Interest Rate** *(%)*	**Maturity**		**Amount**	**Use of Proceeds**
ITC						
First mortgage bonds	March	4.00	2053	US	225	*(1) (2) (3) (4)*
First mortgage bonds	November	4.32	2051	US	175	*(2) (3) (4)*
UNS Energy						
Unsecured notes	November	4.85	2048	US	300	*(1) (4)*
Central Hudson						
Unsecured notes	June	4.27	2048	US	25	*(3) (4)*
Unsecured notes	October	3.99	2026	US	40	*(1) (3) (4)*
Unsecured notes	October	4.21	2033	US	40	*(1) (3) (4)*
FortisBC Energy						
Unsecured debentures	December	3.85	2048		200	*(2) (4)*
FortisAlberta						
Unsecured debentures	September	3.73	2048		150	*(2) (4)*
FortisOntario						
Unsecured notes	August	4.10	2048		100	*(1) (4)*
Maritime Electric						
First mortgage bonds	December	4.15	2058		40	*(2) (4)*
FortisTCI						
Unsecured notes	February	*(5)*	2023	US	25	*(6)*
Unsecured non-revolving term loan *(7)*	September	*(5)*	2025	US	5	*(4)*

(1) Repay maturing long-term debt
(2) Repay credit facility borrowings
(3) Finance capital expenditures
(4) General corporate purposes
(5) Floating rate of a one-month LIBOR plus a spread of 1.75%
(6) Repay a hurricane-related emergency standby loan
(7) Maximum amount of borrowings under this agreement is US$10 million.

Long-Term Debt Repayments

The consolidated requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows.

(year)		**Total** *(in millions)*
2019	$	926
2020		731
2021		1,324
2022		1,125
2023		1,605
Thereafter		18,520
	$	24,231

Credit Facilities

As at December 31, 2018, the Corporation and its subsidiaries had consolidated credit facilities of approximately $5.2 billion, of which approximately $3.9 billion was unused, including $1.0 billion unused under the Corporation's committed revolving corporate credit facility.

The following summarizes the credit facilities of the Corporation and its subsidiaries.

(in millions)	Regulated Utilities	Corporate and Other	**2018**	2017
Total credit facilities	$ 3,780	$ 1,385	**$ 5,165**	$ 4,952
Credit facilities utilized:				
Short-term borrowings *(1)*	(60)	—	**(60)**	(209)
Long-term debt (including current portion) *(2)*	(731)	(335)	**(1,066)**	(671)
Letters of credit outstanding	(65)	(54)	**(119)**	(129)
Credit facilities unutilized	$ 2,924	$ 996	**$ 3,920**	$ 3,943

(1) The weighted average interest rate was approximately 4.2% (December 31, 2017 - 1.8%).
(2) The weighted average interest rate was approximately 3.3% (December 31, 2017 - 2.5%). The current portion was $735 million (December 31, 2017 - $312 million).

Credit facilities are syndicated primarily with large banks in Canada and the United States, with no one bank holding more than 20% of the total facilities. Approximately $5.0 billion of the total credit facilities are committed facilities with maturities ranging from 2019 through 2023.

Consolidated credit facilities of approximately $5.2 billion as at December 31, 2018 are itemized below.

(in millions)		**Amount**	**Maturity**
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC *(1)*	US	900	October 2022
UNS Energy	US	500	October 2022
Central Hudson	US	250	*(2)*
FortisBC Energy		700	August 2023
FortisAlberta		250	August 2023
FortisBC Electric		150	April 2023
Other Electric		190	*(3)*
Other Electric	US	50	January 2020
Corporate and Other		1,350	*(4)*
Other facilities			
Central Hudson - uncommitted credit facility	US	40	n/a
FortisBC Electric - unsecured demand overdraft facility		10	n/a
Other Electric - unsecured demand facilities		25	n/a
Other Electric - unsecured demand facility and emergency standby loan	US	60	April 2019
Corporate and Other - unsecured non-revolving facility		35	n/a

(1) ITC also has a US$400 million commercial paper program, under which no amounts were outstanding as at December 31, 2018.
(2) US$50 million in July 2020 and US$200 million in October 2020
(3) $50 million in February 2019, $40 million in June 2021, and $100 million in August 2023
(4) $1.3 billion in July 2023, with the option to increase by an amount up to $500 million, and $50 million in April 2021

17. CAPITAL LEASE AND FINANCE OBLIGATIONS

Capital Lease Obligations

UNS Energy
Following the acquisition of Gila River generating station Units 1 and 2 by a third party with whom TEP has a power purchase agreement, TEP anticipates exercising its option to purchase Gila River Unit 2 in December 2019 for approximately $224 million (US$164 million). Over the 20-month lease term, TEP will pay a monthly demand charge consisting of a capacity charge and an operating fee.

For 2018 $10 million (2017 - nil) of demand charges were recognized related to the Gila River Unit 2 capital lease obligation.

TEP is party to two Springerville Common Facilities leases with fixed purchase options totalling US$68 million and initial terms to January 2021. TEP has the option to renew the leases for periods of two or more years or exercise the purchase options. Additionally, TEP has entered into agreements with third parties that if the Springerville Common Facilities leases are not renewed, TEP will exercise the purchase options thereunder and the third parties would be obligated to buy a portion of these facilities or continue to make payments to TEP for their use.

The Springerville Common Facilities lease obligations bear interest at a six-month LIBOR plus a spread of 2.00%. TEP holds an interest rate swap that effectively fixes the LIBOR rate at 5.77% on $16 million (December 31, 2017 - $23 million) of the total lease obligation of $19 million (December 31, 2017 - $26 million). The swap is recognized as a cash flow hedge (Note 28).

For 2018 $3 million (2017 - $4 million) of interest expense and $8 million (2017 - $8 million) of depreciation expense was recognized related to the Springerville capital lease obligation.

FortisBC Electric
FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant hydroelectric plant ("Brilliant Plant") in British Columbia. FortisBC Electric operates and maintains the Brilliant Plant under the BPPA, which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Approximately 94% of the output from the Brilliant Plant is purchased by FortisBC Electric through the BPPA. The capital lease obligation bears interest at a composite rate of 5.00%. Included in energy supply costs was $28 million (2017 - $27 million) recognized in accordance with the BPPA, as approved by the BCUC.

FortisBC Electric also has a capital lease obligation with respect to the operation of the Brilliant Terminal Station ("BTS") under an agreement, which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 9.00%. Included in operating expenses was $3 million (2017 - $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC.

Finance Obligations

Between 2000 and 2005 FortisBC Energy entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FortisBC Energy. These assets are integral equipment to real estate assets and the transactions have been accounted for as finance transactions, with the proceeds thereof recognized as finance obligations. Lease payments, net of the portion recognized as interest expense, reduce the finance obligations.

The finance obligations have implicit interest rates ranging from 6.90% to 7.48% and are being repaid over an initial 35-year period with an early termination option after 17 years. If the Company exercises this option, it would pay the municipality an early termination payment equal to the carrying value of the obligation at termination. In October 2018 FortisBC Energy exercised an early termination payment option in the amount $27 million on one of these arrangements.

Capital Lease and Finance Obligations Repayments

Present values of the minimum lease payments over the next five years and thereafter are as follows.

(year)		**Total** *(in millions)*
2019	$	313
2020		77
2021		80
2022		49
2023		47
Thereafter		1,885
	$	2,451
Less: Imputed interest and executory costs		(1,809)
Total capital lease and finance obligations		642
Less: Current installments		(252)
	$	390

18. OTHER LIABILITIES

(in millions)	**2018**	2017
Defined benefit pension plans (Note 25)	**$ 391**	$ 393
OPEBs (Note 25)	**350**	381
Asset retirement obligations (Note 3)	**111**	71
Customer and other deposits	**57**	67
Stock-based compensation plans (Note 22)	**56**	39
Mine reclamation obligations *(1)*	**40**	40
Manufactured gas plant site remediation *(2)*	**32**	34
Fair value of derivatives (Note 28)	**30**	37
Deferred compensation plan (Note 11)	**29**	28
Waneta Partnership promissory note (Note 10)	**—**	63
Other *(3)*	**42**	57
	$ 1,138	$ 1,210

(1) TEP pays ongoing reclamation costs related to three coal mines that supply generating facilities in which it has an ownership interest but does not operate. Costs are deferred as a regulatory asset and recovered from customers as permitted by the regulator. TEP's share of the reclamation costs is estimated to be $90 million (US$66 million) upon expiry of the coal agreements between 2019 and 2031. The present value of the estimated future liability is shown in the table above.

(2) Environmental regulations require Central Hudson to investigate sites at which the Company or its predecessors once owned and/or operated manufactured gas plants and, if necessary, remediate those sites. Costs are accrued based on the amounts that can be reasonably estimated. As at December 31, 2018, an obligation of $64 million (US$47 million) was recognized, including a current portion of $32 million (US$23 million) recognized in accounts payable and other current liabilities (Note 15). Central Hudson has notified its insurers that it intends to seek reimbursement where insurance coverage exists. Differences between actual costs and the associated rate allowances are deferred as a regulatory asset for future recovery (Note 9).

(3) Primarily includes long-term accrued liabilities, deferred lease revenue, funds received in advance of expenditures and unrecognized tax benefits.

19. EARNINGS PER COMMON SHARE

Diluted earnings per share ("EPS") was calculated using the treasury stock method for options.

	2018			2017		
	Net Earnings to Common Shareholders *(in millions)*	**Weighted Average Shares *(in millions)***	**EPS**	Net Earnings to Common Shareholders *(in millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**$ 1,100**	**424.7**	**$ 2.59**	$ 963	415.5	$ 2.32
Potential dilutive effect of stock options	**—**	**0.5**		—	0.7	
Diluted EPS	**$ 1,100**	**425.2**	**$ 2.59**	$ 963	416.2	$ 2.31

20. PREFERENCE SHARES

Authorized
An unlimited number of First Preference Shares and Second Preference Shares, without nominal or par value.

Issued and outstanding	**2018**		2017	
	Number of Shares	**Amount**	Number of Shares	Amount
First Preference Shares	***(in thousands)***	***(in millions)***	*(in thousands)*	*(in millions)*
Series F	**5,000**	**$ 122**	5,000	$ 122
Series G	**9,200**	**225**	9,200	225
Series H	**7,025**	**172**	7,025	172
Series I	**2,975**	**73**	2,975	73
Series J	**8,000**	**196**	8,000	196
Series K	**10,000**	**244**	10,000	244
Series M	**24,000**	**591**	24,000	591
	66,200	**$ 1,623**	66,200	$ 1,623

Characteristics of the First Preference Shares are as follows.

First Preference Shares *(1) (2)*	**Initial Yield** *(%)*	**Annual Dividend** *($)*	**Reset Dividend Yield** *(%)*	**Earliest Redemption and/or Conversion Option Date**	**Redemption Value** *($)*	**Right to Convert on a One-For-One Basis**
Perpetual fixed rate						
Series F	4.90	1.2250	—	December 1, 2011	25.00	—
Series J *(3)*	4.75	1.1875	—	December 1, 2017	25.75	—
Fixed rate reset *(4) (5)*						
Series G *(6)*	5.25	1.0983	2.13	September 1, 2013	25.00	—
Series H	4.25	0.6250	1.45	June 1, 2015	25.00	Series I
Series K	4.00	1.0000	2.05	March 1, 2019	25.00	Series L
Series M	4.10	1.0250	2.48	December 1, 2019	25.00	Series N
Floating rate reset *(5) (7)*						
Series I *(3)*	2.10	—	1.45	June 1, 2015	25.50	Series H
Series L	—	—	2.05	March 1, 2024	—	Series K
Series N	—	—	2.48	December 1, 2024	—	Series M

(1) Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal installments on the first day of each quarter.
(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption, and in the case of the First Preference Shares that reset, on every fifth anniversary date thereafter.
(3) First Preference Shares, Series J were redeemable at $26.00 until December 1, 2018, decreasing by $0.25 each year until December 1, 2021 and redeemable at $25.00 per share thereafter. First Preference Shares, Series I are redeemable at $25.50 per share, up to but excluding June 1, 2020, and at $25.00 per share on June 1, 2020, and on every fifth anniversary date thereafter.
(4) On the redemption and/or conversion option date, and each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.
(5) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their Shares into an equal number of Cumulative Redeemable First Preference Shares of a specified series.
(6) The annual dividend per share for the First Preference Shares, Series G was reset from $0.9708 to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.
(7) The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.

On the liquidation, dissolution or winding-up of Fortis, holders of common shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of First and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or ratably with the holders of the common shares.

21. ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)	Opening Balance	Net Change	Ending Balance
2018			
Unrealized foreign currency translation gains (losses)			
On net investments in foreign operations	**$ 247**	**$ 1,223**	**$ 1,470**
On hedges of net investments in foreign operations	**(172)**	**(372)**	**(544)**
Income tax (expense) recovery	**(1)**	**11**	**10**
	74	**862**	**936**
Other			
Cash flow hedges (Note 28)	**10**	**1**	**11**
Unrealized employee future benefits (losses) gains (Note 25)	**(26)**	**6**	**(20)**
Income tax recovery (expense)	**3**	**(2)**	**1**
	(13)	**5**	**(8)**
Accumulated other comprehensive income	**$ 61**	**$ 867**	**$ 928**
2017			
Unrealized foreign currency translation gains (losses)			
On net investments in foreign operations	$ 1,227	$ (980)	$ 247
On hedges of net investments in foreign operations	(472)	300	(172)
Income tax recovery (expense)	1	(2)	(1)
	756	(682)	74
Other			
Cash flow hedges (Note 28)	8	2	10
Unrealized employee future benefits losses (Note 25)	(22)	(4)	(26)
Income tax recovery	3	—	3
	(11)	(2)	(13)
Accumulated other comprehensive income	$ 745	$ (684)	$ 61

22. STOCK-BASED COMPENSATION PLANS

Stock Options

Officers and certain key employees of Fortis and its subsidiaries are eligible for grants of options to purchase common shares of the Corporation. Options are exercisable for a period of 10 years from the grant date, expire no later thanthree years after the termination, death or retirement of the optionee, and vest evenly over a four-year period on each anniversary of the grant date.

The following options were granted in 2018 and 2017.

	2018		2017
	February	**March**	February
Options granted *(#)*	**721,536**	**39,972**	774,924
Exercise price *($)* (1)	**41.27**	**42.00**	42.36
Grant date fair value *($)*	**3.43**	**4.08**	3.22
Valuation assumptions:			
Dividend yield *(%)* (2)	**3.7**	**3.7**	3.8
Expected volatility *(%)* (3)	**15.5**	**15.7**	16.1
Risk-free interest rate *(%)* (4)	**2.1**	**2.0**	1.2
Weighted average expected life *(years)* (5)	**5.6**	**5.6**	5.6

(1) Five-day VWAP immediately preceding the grant date
(2) Reflects average annual dividend yield up to the grant date and the weighted average expected life of the options
(3) Reflects historical experience over a period equal to the weighted average expected life of the options
(4) Government of Canada benchmark bond yield at the grant date that covers the weighted average expected life of the options
(5) Reflects historical experience

The following table summarizes information related to stock options for 2018.

	Total Options		**Non-vested Options** *(1)*	
	Number of Options	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Grant Date Fair Value**
Options outstanding, January 1, 2018	**3,702,294**	**$ 36.65**	**1,812,319**	**$ 2.86**
Granted	**761,508**	**$ 41.31**	**761,508**	**$ 3.46**
Exercised	**(357,120)**	**$ 33.49**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(711,484)**	**$ 2.88**
Cancelled/Forfeited	**(91,216)**	**$ 40.44**	**(91,216)**	**$ 3.08**
Options outstanding, December 31, 2018	**4,015,466**	**$ 37.73**	**1,771,127**	**$ 3.10**
Options vested, December 31, 2018 *(2)*	**2,244,339**	**$ 35.40**		

(1) As at December 31, 2018, there was $5 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.
(2) As at December 31, 2018, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $23 million.

The following table summarizes additional stock option information.

(in millions)	**2018**	2017
Stock option expense recognized	**$ 2**	$ 3
Stock options exercised:		
Cash received for exercise price	**12**	40
Intrinsic value realized by employees	**3**	15
Fair value of options that vested	**2**	2

Directors' DSU Plan

Directors of the Corporation who are not officers are eligible for grants of DSUs representing the equity portion of their annual compensation. Directors can further elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine that special circumstances justify the grant of additional DSUs to a director.

Each DSU vests at the grant date, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash.

The following table summarizes information related to DSUs.

	2018	2017
Number of Units		
Beginning of year	**184,795**	199,411
Granted	**32,132**	31,453
Notional dividends reinvested	**7,518**	7,294
Paid out	**(47,898)**	(53,363)
End of year	**176,547**	184,795
Additional Information *(in millions)*		
Compensation expense recognized	**$ 2**	$ 3
Cash payout *(1)*	**2**	2
Accrued liability as at December 31 *(2)*	**8**	9

(1) Reflects a weighted-average payout price of $43.15 per DSU (2017 - $45.37)
(2) Recognized at the respective December 31st VWAP (Note 3) and included in long-term other liabilities (Note 18)

PSU Plans

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of PSUs representing a component of their long-term compensation.

Each PSU vests over a three-year period or immediately upon retirement eligibility of the holder, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash. At the end of the three-year vesting period, cash payouts are the product of: (i) the numbers of units vested; (ii) the VWAP of the Corporation's common shares for the five trading days prior to the maturity date; and (iii) a payout percentage that may range from 0% to 200%.

The payout percentage is based on the Corporation's performance over the three-year vesting period, mainly determined by: (i) the Corporation's total shareholder return as compared to a predefined peer group of companies; and (ii) the Corporation's cumulative EPS, or for certain subsidiaries the Company's cumulative net income, as compared to the target established at the time of the grant.

The following table summarizes information related to PSUs.

	2018	2017
Number of Units		
Beginning of year	**1,350,960**	931,951
Granted	**668,995**	711,749
Notional dividends reinvested	**66,280**	44,893
Paid out	**(280,993)**	(239,509)
Cancelled/forfeited	**(42,471)**	(16,910)
Transferred to RSU Plan	**—**	(81,214)
End of year	**1,762,771**	1,350,960
Additional Information *(in millions)*		
Compensation expense recognized	**$ 22**	$ 26
Compensation expense unrecognized *(1)*	**27**	17
Cash payout *(2)*	**14**	11
Accrued liability as at December 31 *(3)*	**50**	41
Aggregate intrinsic value as at December 31 *(4)*	**77**	58

(1) Relates to unvested PSUs and is expected to be recognized over a weighted-average period of two years
(2) Reflects a weighted-average payout price of $46.01 per PSU and a payout percentage of 109% (2017 - $41.46 and 113%, respectively)
(3) Recognized at the respective December 31st VWAP (Note 3) and included in accounts payable and other current liabilities and in long-term other liabilities (Notes15 and 18)
(4) Relates to outstanding PSUs and reflects a weighted-average contractual life of one year

RSU Plans

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of RSUs representing a component of their long-term compensation.

Each RSU vests over a three-year period or immediately upon retirement eligibility of the holder, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash.

The following table summarizes information related to RSUs.

	2018	2017
Number of Units		
Beginning of year	**482,763**	123,612
Granted	**305,686**	349,496
Notional dividends reinvested	**26,263**	15,407
Paid out	**(75,427)**	(74,876)
Cancelled/forfeited	**(22,267)**	(12,090)
Transferred from PSU plan	**—**	81,214
End of year	**717,018**	482,763
Additional Information *(in millions)*		
Compensation expense recognized	**$ 11**	$ 8
Compensation expense unrecognized *(1)*	**15**	11
Cash payout *(2)*	**3**	3
Accrued liability as at December 31 *(3)*	**19**	11
Aggregate intrinsic value as at December 31 *(4)*	**34**	22

(1) Relates to unvested RSUs and is expected to be recognized over a weighted-average period of two years
(2) Reflects a weighted-average payout price of $45.55 per RSU (2017 - $43.42)
(3) Recognized at the respective December 31st VWAP (Note 3) and included in accounts payable and other current liabilities and in long-term other liabilities (Notes15 and 18)
(4) Relates to outstanding RSUs and reflects a weighted-average contractual life of one year

23. OTHER INCOME, NET

(in millions)	2018	2017
Equity component of AFUDC	**$ 64**	$ 74
Interest income	**15**	14
Equity (loss) income - BEL	**(1)**	4
Net periodic pension cost	**(1)**	(11)
Net foreign exchange gain *(1)*	**—**	26
Other	**(17)**	9
	$ 60	$ 116

(1) Includes a one-time $21 million unrealized foreign exchange gain on US dollar-denominated affiliate loan in 2017

24. INCOME TAXES

Deferred Income Tax Assets and Liabilities

The significant components of deferred income tax assets and liabilities consist of the following.

(in millions)	**2018**	2017
Gross deferred income tax assets		
Regulatory liabilities	**$ 635**	$ 596
Tax loss and credit carryforwards	**522**	571
Employee future benefits	**153**	143
Unrealized foreign exchange losses on long-term debt	**69**	28
Other	**76**	51
	1,455	1,389
Valuation allowance	**(56)**	(44)
Net deferred income tax asset	**$ 1,399**	$ 1,345
Gross deferred income tax liabilities		
PPE	**$ (3,780)**	$ (3,353)
Regulatory assets	**(203)**	(203)
Intangible assets	**(102)**	(87)
	(4,085)	(3,643)
Net deferred income tax liability	**$ (2,686)**	$ (2,298)

The deferred income tax assets associated with unrealized foreign exchange losses on long-term debt reflect $56 million of unrealized capital losses as at December 31, 2018 (December 31, 2017 - $44 million). These deferred income tax assets can only be utilized if the Corporation has capital gains to offset these losses once realized. Management believes that it is more likely than not that Fortis will not be able to generate sufficient future capital gains and, consequently, the Corporation recognized a valuation allowance.

Management believes that, based on its historical pattern of taxable income, Fortis will produce the necessary income in the future to realize all other deferred income tax assets.

Unrecognized Tax Benefits

(in millions)	**2018**	2017
Beginning of year	**$ 28**	$ 23
Additions related to the current year	**6**	13
Adjustments related to prior years and U.S. Tax Reform	**4**	(8)
End of year	**$ 38**	$ 28

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2018. Fortis has not recognized interest expense in 2018 and 2017 related to unrecognized tax benefits.

Income Tax Expense

(in millions)		**2018**		2017
Canadian				
Earnings before income tax expense	**$**	**376**	$	461
Current income tax		**51**		41
Deferred income tax		**(25)**		16
Total Canadian	**$**	**26**	$	57
Foreign				
Earnings before income tax expense	**$**	**1,075**	$	1,252
Current income tax		**(22)**		3
Deferred income tax		**161**		528
Total Foreign	**$**	**139**	$	531
Income tax expense	**$**	**165**	$	588

Income tax expense differs from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income tax expense. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except %)		**2018**		2017
Earnings before income tax expense	**$**	**1,451**	$	1,713
Combined Canadian federal and provincial statutory income tax rate		**28.5%**		28.0%
Expected federal and provincial taxes at statutory rate	**$**	**414**	$	480
Increase (decrease) resulting from:				
Enactment of U.S. Tax Reform *(1)*		**—**		168
Foreign and other statutory rate differentials		**(110)**		31
Remeasurement of deferred tax liabilities		**(44)**		—
AFUDC		**(14)**		(26)
Effects of rate-regulated accounting:				
Difference between depreciation claimed for income tax and accounting purposes		**(34)**		(26)
Items capitalized for accounting purposes but expensed for income tax purposes		**(21)**		(21)
Other		**(26)**		(18)
Income tax expense	**$**	**165**	$	588
Effective tax rate		**11.4%**		34.3%

(1) In 2017 the *Tax Cuts and Jobs Act* implemented significant changes to U.S. tax legislation, including a reduction in the U.S. federal corporate income tax from 35% to 21%, effective January 1, 2018. The Corporation's U.S. utilities and holding companies were required to remeasure their deferred tax assets and liabilities at the new corporate income tax rate as at the date of enactment. The one-time remeasurement resulted in an unfavourable earnings impact of $168 million recognized in deferred income tax expense ($146 million after non-controlling interest).

Income Tax Carryforwards

(in millions)	Expiring Year		**2018**
Canadian			
Capital loss	n/a	**$**	**59**
Non-capital loss	2025-2038		**387**
Other tax credits	2026-2037		**2**
			448
Unrecognized			**(15)**
			433
Foreign			
Federal and state net operating loss	2022-2038		**2,130**
Other tax credits	2021-2038		**115**
			2,245
Total income tax carryforwards recognized as at December 31		**$**	**2,678**

The Corporation and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal and British Columbia). The Corporation's 2012 to 2018 taxation years are still open for audit in the Canadian jurisdictions and its 2014 to 2018 taxation years are still open for audit in the United States jurisdictions.

25. EMPLOYEE FUTURE BENEFITS

For defined benefit pension and OPEB plans, the benefit obligation and fair value of plan assets are measured as at December 31.

For the Corporation's Canadian and Caribbean subsidiaries, actuarial valuations to determine funding contributions for pension plans are required at least every three years. The most recent valuations were as of December 31, 2015 for FortisBC Energy (plan covering non-unionized employees); December 31, 2016 for FortisBC Electric and FortisBC Energy (plans covering unionized employees); December 31, 2017 for Newfoundland Power, FortisAlberta, FortisOntario and the Corporation; and December 31, 2018 for Caribbean Utilities.

ITC, UNS Energy and Central Hudson perform annual actuarial valuations as their funding requirements are based on maintaining minimum annual targets, all of which have been met.

The Corporation's investment policy is to ensure that the defined benefit pension and OPEB plan assets, together with expected contributions, are invested in a prudent and cost-effective manner to optimally meet the liabilities of the plans. The investment objective is to maximize returns in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and recognized expense.

Allocation of Plan Assets as at December 31

(weighted-average %)	**2018 Target Allocation**	**2018**	2017
Equities	**46**	**45**	47
Fixed income	**47**	**47**	46
Real estate	**6**	**7**	6
Cash and other	**1**	**1**	1
	100	**100**	100

Fair value of plan assets as at December 31

(in millions)	**Level 1** *(1)*	**Level 2** *(1)*	**Level 3** *(1)*	**Total**
2018				
Equities	**$ 508**	**$ 885**	**$ —**	**$ 1,393**
Fixed income	**144**	**1,338**	**—**	**1,482**
Real estate	**—**	**14**	**190**	**204**
Private equities	**—**	**—**	**25**	**25**
Cash and other	**8**	**11**	**—**	**19**
	$ 660	**$ 2,248**	**$ 215**	**$ 3,123**
2017				
Equities	$ 522	$ 949	$ —	$ 1,471
Fixed income	133	1,289	—	1,422
Real estate	—	13	168	181
Private equities	—	—	22	22
Cash and other	8	14	—	22
	$ 663	$ 2,265	$ 190	$ 3,118

(1) Refer to Note 28 for a description of the fair value hierarchy.

The following table reconciles the changes in the fair value of pension plan assets that have been measured using Level 3 inputs.

(in millions)	**2018**	2017
Balance, beginning of year	**$ 190**	$ 113
Return on plan assets	**15**	12
Foreign currency translation	**3**	(2)
Purchases, sales and settlements	**7**	67
Balance, end of year	**$ 215**	$ 190

Funded Status	**Defined Benefit Pension Plans**		**OPEB Plans**	
(in millions)	**2018**	2017	**2018**	2017
Change in benefit obligation *(1)*				
Balance, beginning of year	**$ 3,215**	$ 3,037	**$ 665**	$ 676
Service costs	**84**	76	**31**	27
Employee contributions	**16**	16	**2**	2
Interest costs	**114**	115	**23**	25
Benefits paid	**(145)**	(133)	**(26)**	(22)
Actuarial losses (gains)	**(217)**	217	**(69)**	(14)
Past service credits/plan amendments	**(1)**	—	**(3)**	(3)
Foreign currency translation	**141**	(113)	**32**	(26)
Balance, end of year *(2)*	**$ 3,207**	$ 3,215	**$ 655**	$ 665
Change in value of plan assets				
Balance, beginning of year	**$ 2,841**	$ 2,646	**$ 277**	$ 252
Actual return on plan assets	**(93)**	336	**(13)**	37
Benefits paid	**(137)**	(127)	**(26)**	(22)
Employee contributions	**16**	16	**2**	2
Employer contributions	**79**	69	**29**	26
Foreign currency translation	**124**	(99)	**24**	(18)
Balance, end of year	**$ 2,830**	$ 2,841	**$ 293**	$ 277
Funded status	**$ (377)**	$ (374)	**$ (362)**	$ (388)
Balance sheet presentation				
Long-term assets (Note 11)	**$ 26**	$ 31	**$ 1**	$ 3
Current liabilities (Note 15)	**(12)**	(12)	**(13)**	(10)
Long-term liabilities (Note 18)	**(391)**	(393)	**(350)**	(381)
	$ (377)	$ (374)	**$ (362)**	$ (388)

(1) Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans.

(2) The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $2,936 million as at December 31, 2018 (December 31, 2017 - $2,940 million).

Net Benefit Cost	**Defined Benefit Pension Plans**		**OPEB Plans**	
(in millions)	**2018**	2017	**2018**	2017
Service costs	**$ 84**	$ 76	**$ 31**	$ 27
Interest costs	**114**	115	**23**	25
Expected return on plan assets	**(162)**	(151)	**(16)**	(14)
Amortization of actuarial losses	**48**	45	**—**	2
Amortization of past service credits/plan amendments	**—**	—	**(10)**	(12)
Regulatory adjustments	**(1)**	2	**6**	4
Net benefit cost	**$ 83**	$ 87	**$ 34**	$ 32

The following table summarizes the accumulated amounts of net benefit cost that have not yet been recognized in earnings or comprehensive income and shows their classification on the consolidated balance sheets.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2018**	2017	**2018**	2017
Unamortized net actuarial losses (gains)	**$ 19**	$ 22	**$ (2)**	$ —
Unamortized past service costs	**1**	1	**2**	3
Income tax recovery	**(3)**	(5)	**(1)**	(1)
Accumulated other comprehensive income (Note 21)	**$ 17**	$ 18	**$ (1)**	$ 2
Net actuarial losses (gains)	**$ 457**	$ 443	**$ (25)**	$ 17
Past service credits	**(10)**	(11)	**(16)**	(23)
Other regulatory deferrals	**15**	10	**27**	27
	$ 462	$ 442	**$ (14)**	$ 21
Regulatory assets (Note 9)	**$ 462**	$ 442	**$ 23**	$ 68
Regulatory liabilities (Note 9)	**—**	—	**(37)**	(47)
Net regulatory assets	**$ 462**	$ 442	**$ (14)**	$ 21

The following table summarizes the components of net benefit cost recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2018**	2017	**2018**	2017
Current year net actuarial (gains) losses	**$ (3)**	$ 5	**$ (2)**	$ (1)
Past service (credits) costs/plan amendments	**—**	—	**(1)**	2
Amortization of actuarial losses	**(1)**	(1)	**—**	—
Foreign currency translation	**1**	(1)	**—**	—
Income tax recovery	**2**	—	**—**	—
Total recognized in comprehensive income	**$ (1)**	$ 3	**$ (3)**	$ 1
Current year net actuarial losses (gains)	**$ 41**	$ 24	**$ (39)**	$ (35)
Past service credits/plan amendments	**—**	—	**(3)**	(5)
Amortization of actuarial losses	**(47)**	(44)	**—**	(1)
Amortization of past service (costs) credits	**1**	—	**11**	12
Foreign currency translation	**21**	(17)	**(3)**	2
Regulatory adjustments	**4**	(1)	**(1)**	(6)
Total recognized in regulatory assets	**$ 20**	$ (38)	**$ (35)**	$ (33)

Net actuarial losses of $1 million are expected to be amortized to net benefit cost from accumulated other comprehensive income in 2019 related to defined benefit pension plans.

Net actuarial losses of $24 million, past service credits of $1 million and regulatory adjustments of $1 million are expected to be amortized to net benefit cost from regulatory assets in 2019 related to defined benefit pension plans. Past service credits of $8 million, net actuarial gains of $4 million and regulatory adjustments of $4 million are expected to be amortized to net benefit cost from regulatory assets in 2019 related to OPEB plans.

Significant Assumptions	Defined Benefit Pension Plans		OPEB Plans	
(weighted-average %)	**2018**	2017	**2018**	2017
Discount rate during the year *(1)*	**3.56**	3.98	**3.57**	3.96
Discount rate as at December 31	**4.07**	3.58	**4.13**	3.59
Expected long-term rate of return on plan assets *(2)*	**5.80**	5.97	**5.48**	5.81
Rate of compensation increase	**3.35**	3.34	**—**	—
Health care cost trend increase as at December 31 *(3)*	**—**	—	**4.61**	4.71

(1) ITC and UNS use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.
(2) Developed by management with assistance from external actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. Best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.
(3) The projected 2019 weighted-average health care cost trend rate for OPEB plans is 6.35% and is assumed to decrease over the next 14 years to the weighted-average ultimate health care cost trend rate of 4.61% in 2032 and thereafter.

The following table summarizes for 2018 the effects of changing the health care cost trend rate by 1%.

(in millions)	1% increase	1% decrease
Increase (decrease) in accumulated benefit obligation	**$ 85**	**$ (67)**
Increase (decrease) in service and interest costs	**11**	**(8)**

Expected Benefit Payments	Defined Benefit Pension Payments	OPEB
(year)	*(in millions)*	*(in millions)*
2019	$ 147	$ 26
2020	152	28
2021	157	30
2022	165	32
2023	170	33
2024-2028	946	185

During 2019 the Corporation expects to contribute $47 million for defined benefit pension plans and $31 million for OPEB plans.

In 2018 the Corporation expensed $38 million (2017 - $38 million) related to defined contribution pension plans.

26. TERMINATED ACQUISITION

In May 2017 Fortis had entered into an agreement with Teck Resources Limited to acquire a two-thirds ownership interest in the Waneta Dam and related transmission assets in British Columbia. In August 2017 BC Hydro exercised its right of first offer in this regard. Consequently, the purchase agreement with Fortis was terminated, resulting in the payment of a $28 million break fee to Fortis, which was recognized in operating expenses.

27. SUPPLEMENTARY CASH FLOW INFORMATION

(in millions)	2018	2017
Cash paid for		
Interest	**$ 969**	$ 927
Income taxes	**73**	69
Change in working capital		
Accounts receivable and other current assets	**$ (204)**	$ (74)
Prepaid expenses	**1**	(3)
Inventories	**(8)**	(6)
Regulatory assets - current portion	**16**	39
Accounts payable and other current liabilities	**99**	119
Regulatory liabilities - current portion	**(6)**	(172)
	$ (102)	$ (97)
Non-cash investing and financing activities		
Accrued capital expenditures	**$ 328**	$ 307
Common share dividends reinvested	**272**	253
Gila River generating station Unit 2 capital lease	**223**	—
Contributions in aid of construction	**14**	35
Exercise of stock options into common shares	**1**	5

28. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery.

The Corporation records all derivatives at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the derivatives as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

Cash flows associated with the settlement of all derivatives are included in operating activities in the consolidated statements of cash flows.

Energy contracts subject to regulatory deferral
UNS Energy holds electricity power purchase contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values were measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values were measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts and financial commodity swaps to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2018, unrealized losses of $57 million (December 31, 2017 - $87 million) were recognized as regulatory assets and unrealized gains of $9 million (December 31, 2017 - $2 million) were recognized in regulatory liabilities (Note 9).

Energy contracts not subject to regulatory deferral
UNS Energy holds wholesale trading contracts that qualify as derivatives to fix power prices and realize potential margin, of which 10% of any realized gains are shared with customers through rate stabilization accounts. Fair values were measured using a market approach using independent third-party information, where possible.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in earnings. During 2018 unrealized losses of $12 million (2017 - unrealized gains of $36 million) were recognized in revenue.

Foreign exchange contracts
The Corporation holds US dollar foreign exchange contracts to mitigate exposure to volatility of foreign exchange rates. The contracts expire in 2019 and have a combined notional amount of $161 million. Fair value was measured using independent third-party information.

Unrealized gains and losses associated with changes in fair value are recognized in earnings. During 2018 unrealized losses of $11 million (2017 - unrealized gains of $3 million) were recognized in other income, net.

Interest rate and total return swaps
UNS Energy holds an interest rate swap to mitigate exposure to volatility in variable interest rates on capital lease obligations (Note 17). The swap expires in 2020 and has a notional amount of $16 million. Fair value was measured using an income valuation approach based on six-month LIBOR.

Unrealized gains and losses associated with changes in the fair value of this interest rate swap, which was designated as a cash flow hedge, are recognized in other comprehensive income and reclassified to earnings through interest expense over the life of the hedged debt. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $3 million, net of tax.

The Corporation holds three total return swaps to manage the cash flow risk associated with forecasted future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $41 million and terms ranging from one to three years, expiring in January 2019, 2020 and 2021. Fair value was measured using an income valuation approach based on forward pricing curves.

Unrealized gains and losses associated with changes in the fair value of the total return swaps are recognized in earnings. During 2018 unrealized gains of less than $1 million (2017 - unrealized losses of less than $1 million) were recognized in other income, net.

Other investments
ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses on these funds are recognized in earnings. During 2018 unrealized gains of less than $1 million (2017 - unrealized gains of less than $1 million) were recognized in other income, net.

Recurring Fair Value Measures

The following table presents the fair value of the assets and liabilities that are accounted for at fair value on a recurring basis.

(in millions)	**Level 1** *(1)*	**Level 2** *(1)*	**Level 3** *(1)*	**Total**
As at December 31, 2018				
Assets				
Energy contracts subject to regulatory deferral *(2) (3)*	**$ — $**	**33 $**	**8 $**	**41**
Energy contracts not subject to regulatory deferral *(2)*	**—**	**13**	**3**	**16**
Other investments *(4)*	**155**	**—**	**—**	**155**
	$ 155 $	**46 $**	**11 $**	**212**
Liabilities				
Energy contracts subject to regulatory deferral *(3) (5)*	**$ — $**	**(86) $**	**(3) $**	**(89)**
Energy contracts not subject to regulatory deferral *(5)*	**—**	**(1)**	**—**	**(1)**
Foreign exchange contracts, interest rate and total return swaps *(6)*	**(8)**	**(1)**	**—**	**(9)**
	$ (8) $	**(88) $**	**(3) $**	**(99)**
As at December 31, 2017				
Assets				
Energy contracts subject to regulatory deferral *(2) (3)*	$ — $	19 $	2 $	21
Energy contracts not subject to regulatory deferral *(2)*	—	26	4	30
Foreign exchange contracts *(6)*	3	—	—	3
Other investments *(4)*	78	—	—	78
	$ 81 $	45 $	6 $	132
Liabilities				
Energy contracts subject to regulatory deferral *(3) (5)*	$ (1) $	(103) $	(2) $	(106)
Energy contracts not subject to regulatory deferral *(5)*	—	—	(1)	(1)
Interest rate and total return swaps *(6)*	—	(1)	—	(1)
	$ (1) $	(104) $	(3) $	(108)

(1) Under the hierarchy, fair value is determined using: (i) level 1 - unadjusted quoted prices in active markets; (ii) level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.
(2) Included in accounts receivable and other current assets or other assets
(3) 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.
(4) Included in other assets
(5) Included in accounts payable and other current liabilities or other liabilities
(6) Included in accounts receivable and other current assets, accounts payable and other current liabilities or other liabilities

Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one hierarchical fair value level to another. There were no transfers between levels during 2018.

For level 3 measurements, changes in the unobservable inputs could have a significant impact on fair value. Excluding long-term wholesale trading contracts and certain gas swap contracts, the impacts of fair value changes are subject to regulatory recovery.

The following table reconciles changes in the fair value of level 3 net assets and liabilities.

(in millions)	**2018**	2017
Balance, beginning of year	**$ 3**	$ 2
Realized gains (losses)	**14**	(13)
Settlements	**(9)**	12
Transfers of assets out of level 3	**—**	(2)
Transfers of liabilities out of level 3	**—**	4
Balance, end of year	**$ 8**	$ 3

The Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions, which applies only to its energy contracts. The following table presents the potential offset of counterparty netting.

Energy Contracts *(in millions)*	**Gross Amount Recognized on Balance Sheet**	**Counterparty Netting of Energy Contracts**	**Cash Collateral Received/Posted**	**Net Amount**
As at December 31, 2018				
Derivative assets	**$ 57**	**$ 28**	**$ 16**	**$ 13**
Derivative liabilities	**(90)**	**(28)**	**—**	**(62)**
As at December 31, 2017				
Derivative assets	$ 51	$ 17	$ 7	$ 27
Derivative liabilities	(107)	(17)	—	(90)

Volume of Derivative Activity

As at December 31, 2018, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

As at December 31	**2018**	2017
Energy contracts subject to regulatory deferral *(1)*		
Electricity swap contracts *(GWh)*	**774**	1,291
Electricity power purchase contracts *(GWh)*	**651**	761
Gas swap contracts *(PJ)*	**203**	216
Gas supply contract premiums *(PJ)*	**266**	219
Energy contracts not subject to regulatory deferral *(1)*		
Wholesale trading contracts *(GWh)*	**1,440**	2,387
Gas swap contracts *(PJ)*	**37**	36

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

Credit Risk

For cash equivalents, accounts receivable and other current assets, and long-term other receivables, credit risk is generally limited to the carrying value on the consolidated balance sheets. The Corporation's subsidiaries generally have a large and diversified customer base, which minimizes the concentration of credit risk. Policies in place to minimize credit risk include requiring customer deposits, prepayments and/or credit checks for certain customers, performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. Credit risk is limited as such customers have investment-grade credit ratings. ITC further reduces credit risk by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

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

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and the Corporation may be exposed to credit risk in the event of non-performance by counterparties to derivatives. Credit risk is limited by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy and Central Hudson, certain contractual arrangements require counterparties to post collateral.

The value of derivatives in net liability positions under contracts with credit risk-related contingent features that, if triggered, could require the posting of a like amount of collateral was $75 million as at December 31, 2018 (December 31, 2017 - $57 million).

Foreign Exchange Hedge

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and BECOL is the US dollar. The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased this exposure by designating US dollar-denominated borrowings at the corporate level as a hedge of its net investment in foreign subsidiaries. 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 US dollar-denominated subsidiary earnings.

As at December 31, 2018, US$3,441 million (December 31, 2017 - US$3,385 million) of net investment in foreign subsidiaries was hedged by the Corporation's corporately issued US dollar-denominated long-term debt and approximately US$7,970 million (December 31, 2017 - US$7,548 million) was unhedged. Exchange rate fluctuations associated with the hedged net investment in foreign subsidiaries and the debt serving as the hedge are recognized in accumulated other comprehensive income.

Financial Instruments Not Carried at Fair Value

Excluding long-term debt, the consolidated carrying value of the Corporation's financial instruments approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

As at December 31, 2018, the carrying value of long-term debt, including the current portion, was$24,231 million (December 31, 2017 - $21,535 million) (Note 16) compared to an estimated fair value of$25,110 million (December 31, 2017 - $23,481 million). Long-term debt is fair valued using level 2 inputs.

The fair value of long-term debt is calculated using quoted market prices or, when unavailable, by either: (i) discounting the associated future cash flows 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 with similar maturities. Since the Corporation does not intend to settle the long-term debt prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

29. VARIABLE INTEREST ENTITY

The Waneta Partnership, which owns and operates the Waneta Expansion on the Pend d'Oreille River in British Columbia, is 51% owned by Fortis and 49% by CPC and CBT (Note 10). The Waneta Expansion is operated and maintained by a wholly owned subsidiary of the Corporation and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts. Each partner pays its proportionate share of the costs and is entitled to a proportionate share of the net revenue.

The Corporation's ownership interest is a variable interest entity. Fortis is the primary beneficiary as it has the power to direct the activities of the partnership, the obligation to absorb losses and the right to receive benefits that could be significant to the partnership. Consequently, Fortis consolidates the Waneta Partnership. The Corporation's consolidated financial statements include the following with respect to the Waneta Partnership.

(in millions)	**2018**	2017
Assets		
Cash and cash equivalents	**$ 15**	$ 16
Accounts receivable and other current assets	**15**	14
PPE	**674**	688
Intangible assets	**30**	30
	$ 734	$ 748
Liabilities		
Accounts payable and other current liabilities	**$ (6)**	$ (28)
Other liabilities	**(67)**	(63)
	(73)	(91)
Net assets before partners' equity	**$ 661**	$ 657
Revenue	**$ 94**	$ 93
Expenses		
Operating expenses	**18**	17
Depreciation and amortization	**18**	18
Finance charges	**4**	4
	40	39
Net earnings	**$ 54**	$ 54

Cash used in investing activities at the Waneta Partnership for 2018 included capital expenditures of $27 million (2017 - $5 million). Cash flow related to financing activities for 2018 included dividends paid by the Waneta Partnership to non-controlling interests of $35 million (2017 - $34 million) and advances from non-controlling interests of $11 million (2017 - nil).

30. COMMITMENTS AND CONTINGENCIES

As at December 31, 2018, consolidated commitments in each of the next five years and for periods thereafter, excluding repayments of long-term debt and capital lease and finance obligations separately disclosed in Notes 16 and 17, respectively, were as follows.

(in millions)	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Interest obligations on long-term debt	**$ 16,345**	$ 994	$ 973	$ 950	$ 902	$ 870	$ 11,656
Power purchase obligations *(1)*	**2,438**	254	191	174	170	172	1,477
Renewable power purchase obligations *(2)*	**1,699**	110	110	109	109	108	1,153
Gas purchase obligations *(3)*	**1,348**	359	290	242	202	144	111
Long-term contracts - UNS Energy *(4)*	**777**	176	142	92	60	46	261
ITC easement agreement *(5)*	**436**	14	14	14	14	14	366
Renewable energy credit purchase agreements *(6)*	**146**	24	26	18	11	11	56
Debt collection agreement *(7)*	**119**	3	3	3	3	3	104
Purchase of Springerville Common Facilities *(8)*	**93**	—	—	93	—	—	—
Joint-use asset and shared service agreements	**52**	3	3	3	3	3	37
Operating lease obligations	**51**	8	6	5	4	4	24
Other *(9)*	**530**	108	84	89	38	36	175
Total	**$ 24,034**	$ 2,053	$ 1,842	$ 1,792	$ 1,516	$ 1,411	$ 15,420

(1) The most significant power purchase obligations are described below.

Maritime Electric ($771 million): includes an agreement entitling Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and requiring Maritime Electric to pay its share of the station's capital operating costs for the life of the unit. Maritime Electric also has two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2024.

FortisOntario ($705 million): an agreement with Hydro-Québec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through December 2030.

FortisBC Energy ($522 million): an agreement with BC Hydro for the supply of electricity to the Tilbury liquefied natural gas facility expansion.

FortisBC Electric ($345 million): includes an agreement with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013.

(2) TEP and UNS Electric are party to renewable PPAs, with expiry dates from 2027 through 2043, that require them to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. Amounts shown are the estimated future payments.

(3) 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, 2018.

(4) UNS Energy enters into long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, and the purchase of transmission services for purchased power. Amounts paid for coal depend on actual quantities purchased and delivered. Certain contracts have price adjustment clauses that will affect future costs. These contracts have various expiry dates between 2019 and 2040.

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

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

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

(8) UNS Energy is obligated to purchase an undivided 32.2% interest in the Springerville Common Facilities if the related two leases are not renewed. The initial lease terms expire in January 2021 (Note 17).

(9) Includes stock-based compensation plan obligations, land easements, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Commitments

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Their capital expenditures are largely to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. Consolidated capital expenditures are forecast to be approximately $3.7 billion for 2019 and approximately $17.3 billion over the five-year period from 2019 through 2023.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling $2.3 billion (US$1.7 billion). Central Hudson's maximum commitment is $248 million (US$182 million), for which it has issued a parental guarantee. As at December 31, 2018, there was no obligation under this guarantee.

As at December 31, 2018, FHI had $77 million (December 31, 2017 - $80 million) of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Contingency

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline right of way on reserve lands. The pipeline was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in 2007. The Band seeks cancellation of the right of way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the Minister's consent and returned the matter to the Minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.

31. COMPARATIVE FIGURES

Effective January 1, 2018, the Corporation elected to present, on the statement of cash flows, all borrowings and repayments under committed credit facilities on a gross basis and continue to present borrowings and repayments under uncommitted or demand credit facilities on a net basis as Net Change in Short-Term Borrowings. The presentation change resulted in $365 million, which was previously reported within Net Repayments and Borrowings under Committed Facilities, being reported on a gross basis, with (i) $4,376 million reported as Borrowings under Committed Credit Facilities, (ii) $5,441 million reported as Repayments under Committed Credit Facilities, and (iii) $700 million reported as Net Change in Short-Term Borrowings.

Comparative figures were reclassified to conform with the revised segmentation, as described in Note 5, and to reflect the retrospective adoption of ASU 2017-07, as described in Note 3.

Exhibit 99.3

FORTIS INC.

Management Discussion and Analysis

For the year ended December 31, 2018
Dated February 14, 2019

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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, 2018 ("2018 Annual Financial Statements"). Financial information contained in this MD&A has been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

FORWARD-LOOKING INFORMATION

Fortis includes forward-looking information in the MD&A within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, collectively referred to as "forward-looking information". Forward-looking information included in the MD&A reflects expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: the satisfaction of the conditions and the expected timing of the closing of the sale of the Corporation's interest in the Waneta Expansion hydroelectric project; the Corporation's forecast capital expenditures for the period 2019 through 2023 and potential funding sources for the capital expenditure program; the Corporation's forecast rate base for the period 2019 through 2023; the expectation that capital investment will support growth in earnings and dividends; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to long-term capital in 2019; targeted average annual dividend growth through 2023; timing of refund payments stemming from the ITC incentive adder complaint and the expectation that the order will not have a material impact on the Corporation's earnings or cash flows; expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the nature, timing, benefits, funding sources and expected costs of certain capital projects including, without limitation, the ITC Multi-Value Regional Transmission Projects and 34.5 to 69 kilovolt Transmission Conversion Project, UNS Energy Gila River Natural Gas Generating Station Unit 2, Southline Transmission Project and New Mexico Wind Project, FortisBC Energy expansion of the Tilbury liquefied natural gas facility, Lower Mainland Intermediate Pressure System Upgrade, Eagle Mountain Woodfibre Gas Line Project and Transmission Integrity Management Capabilities Project, the Wataynikaneyap Transmission Power Project and additional opportunities beyond the base plan; the expectation that subsidiary operating expenses and interest costs will be paid out of subsidiary operating cash flows; the expectation that cash required to complete subsidiary capital

expenditure programs will be sourced from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from Fortis; the expectation that maintaining the targeted capital structure of the Corporation's regulated operating subsidiaries will not have an impact on its ability to pay dividends in the foreseeable future; the expectation that cash required from 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, proceeds from the issuance of common shares, preference shares and long-term debt, and proceeds from non-core asset sales; expected consolidated fixed-term debt maturities and repayments in 2019 and over the next five years; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout 2019; 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 information, including, without limitation: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received and the expectation of regulatory stability; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the realization of additional opportunities; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial condition 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 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 territories; the continued tax deferred treatment of earnings from the Corporation's foreign operations; continued maintenance of information technology infrastructure and no material breach of cybersecurity; continued favourable relations with Indigenous Peoples; 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 expenditure program.

Forward-looking information involves significant risks, uncertainties and assumptions. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in this MD&A and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission. Key risk factors for 2019 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; the impact of fluctuations in foreign exchange rates; risk associated with the impacts of less favourable economic conditions on the Corporation's results of operations; risk associated with the completion of the Corporation's 2019 capital expenditure program, including completion of major capital projects in the timelines anticipated and at the expected amounts; and uncertainty in the timing of and access to capital markets to arrange sufficient and cost-effective financing to finance, among other things, capital expenditures and the repayment of maturing debt.

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

CORPORATE OVERVIEW

Fortis is a leader in the North American regulated electric and gas utility industry, with 2018 revenue of $8.4 billion and total assets of $53 billion as at December 31, 2018. The Corporation's 8,800 employees serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. In 2018 the Corporation's electricity systems met a combined peak demand of 33,295 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,599 terajoules.

The Corporation's main business, utility operations, is highly regulated and its earnings are primarily determined under cost of service ("COS") regulation, in combination with performance-based rate-setting ("PBR") mechanisms in certain jurisdictions. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the recovery, on a timely basis, of estimated costs of providing service, 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 to recover prudently incurred costs 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 forecasts established in the rate-setting process. 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.

Entities within the reporting segments that follow operate with substantial autonomy.

Regulated Utilities

ITC: Primarily comprised of ITC Holdings Corp., ITC Investment Holdings Inc. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC. Fortis owns 80.1% of ITC and an affiliate of GIC Private Limited owns a19.9% minority interest.

ITC owns and operates high-voltage transmission lines in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma.

UNS Energy: Comprised of UNS Energy Corporation, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas").

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to approximately 522,000 retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County and parts of Cochise County, as well as in Santa Cruz and Mohave counties. TEP also sells wholesale electricity to other entities in the western United States. Together they own generation capacity of 3,377 MW, including 57 MW of solar capacity. Several generating assets in which they have an interest are jointly owned.

UNS Gas is a regulated gas distribution utility serving approximately 158,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

Central Hudson: Primarily comprised of CH Energy Group, Inc. and Central Hudson Gas & Electric Corporation. Central Hudson is a regulated electric and gas transmission and distribution utility that serves approximately 300,000 electricity customers and 80,000 natural gas customers inportions of New York State's Mid-Hudson River Valley and owns gas-fired and hydroelectric generating capacity totalling 64 MW.

FortisBC Energy: Primarily comprised of FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, providing transmission and distribution services to approximately 1,030,000 customers in more than 135 communities.FortisBC Energy obtains natural gas supplies primarily from northeastern British Columbia and Alberta on behalf of most customers.

FortisAlberta: FortisAlberta Inc. is a regulated electricity distribution utility operating in a substantial portion of southern and central Alberta serving approximately 564,000 customers. It is not involved in the direct sale of electricity.

FortisBC Electric: Primarily comprised of FortisBC Inc., an integrated regulated electric utility operating in the southern interior of British Columbia serving approximately 176,000 customers directly and indirectly. It owns four hydroelectric generating facilities with a combined capacity of 225 MW. It also provides operating, maintenance and management services relating to four hydroelectric generating facilities in British Columbia that are owned by third parties and to the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in which Fortis indirectly holds a 51% controlling interest.

Other Electric: Comprised of utilities in eastern Canada and the Caribbean, as follows: Newfoundland Power Inc. ("Newfoundland Power"); Maritime Electric Company, Limited ("Maritime Electric"); FortisOntario Inc. ("FortisOntario"); a 39% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Partnership"); an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"); FortisTCI Limited and Turks and Caicos Utilities Limited (collectively "FortisTCI"); and a 33% equity investment in Belize Electricity Limited ("BEL").

In January 2019 Fortis reduced its equity investment in Wataynikaneyap Partnership from 49% to 39% to facilitate the inclusion of two additional First Nations communities into the partnership.

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 268,000 customers. Newfoundland Power has a generating capacity of 139 MW, of which 97 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving approximately 81,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 145 MW. FortisOntario is comprised of three regulated electric utilities that provide service to approximately 66,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. Wataynikaneyap Partnership is a partnership between 24 First Nations communities and Fortis with a mandate of connecting remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines (the "Wataynikaneyap Transmission Power Project").

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman, serving approximately 30,000 customers, with a diesel-powered generating capacity of 161 MW. FortisTCI is comprised of two integrated regulated electric utilities that provide electricity to approximately 15,000 customers on certain Turks and Caicos Islands and has a diesel-powered generating capacity of 91 MW. BEL is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

Energy Infrastructure: Primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generation assets in British Columbia include the Corporation's interest in the Waneta Expansion, whose output is sold to British Columbia Hydro and Power Authority ("BC Hydro") and FortisBC Electric under 40-year power purchase agreements ("PPAs"). Generation 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 BEL under 50-year PPAs. Fortis indirectly owns 93.8% of Aitken Creek, with the remainder owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a working gas capacity of 77 billion cubic feet.

In January 2019 the Corporation entered into a definitive agreement with Columbia Power Corporation ("CPC") and Columbia Basin Trust ("CBT") to sell its 51% interest in the Waneta Expansion for approximately $1 billion. CPC and CBT, both 100% owned by the Government of British Columbia, are the Corporation's partners and together currently own 49% of the Waneta Expansion. Fortis expects the transaction to close in the second quarter of 2019 following the satisfaction of customary closing conditions. FortisBC Electric will continue to operate the Waneta Expansion facility and purchase its surplus capacity.

Corporate and Other: Captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments, including net corporate expenses of Fortis and the non-regulated holding company FortisBC Holdings Inc. ("FHI").

CORPORATE STRATEGY

Fortis strives to provide customers with safe, reliable and cost-effective energy service using sustainable practices while delivering long-term profitable growth. The Corporation is a well-diversified, regulated, primarily transmission and distribution business characterized by low-risk, stable and predictable earnings and cash flows.

Earnings per common share and total shareholder return are the primary measures of financial performance. Over the 10-year period ended December 31, 2018, earnings per common share of Fortis grew at a compound annual growth rate of 5.2%. Over the same period, Fortis delivered an average annualized total return to shareholders of 10.5%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 7.2% and 7.9%, respectively, over the same period.

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

KEY TRENDS, RISKS AND OPPORTUNITIES

Energy Industry Developments: The North American energy industry continues to transform. There is a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. Notwithstanding the changes occurring in the utility industry, safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of the utility industry's focus.

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

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

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

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

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

Regulation: The Corporation's key business risk is regulation. Fortis is well positioned to maintain constructive regulatory relationships through local management teams and boards comprised of mostly independent local board members. Commitment by the Corporation's utilities to provide safe and reliable service, operational excellence and positive customer service is also important to ensure supportive regulatory relationships and obtain full cost recovery and competitive returns for the Corporation's shareholders.

All of the Corporation's regulated utilities continue to be actively engaged with each of their regulators and are focused on maintaining constructive regulatory relationships and outcomes. For a further discussion of material regulatory decisions and applications and regulatory risk, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth: The Corporation's $17.3 billion five-year capital expenditure program is expected to increase rate base from $26.1 billion in 2018 to approximately $32.0 billion in 2021 and $35.5 billion in 2023, translating into three- and five-year compound annual growth rates of 7.1% and 6.3%, respectively. Fortis expects this capital investment to support growth in earnings and dividends.

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

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level, at terms ranging between 5 and 40 years. As at December 31, 2018, approximately 80% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately $929 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital expenditure programs and working capital requirements, the Corporation and its subsidiaries have approximately $5.2 billion in credit facilities, of which approximately $3.9 billion was unused as at December 31, 2018. 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 2019.

In December 2018 Fortis filed a short-form base shelf prospectus and re-established its at-the-market common equity program. For additional information, refer to the "Cash Flow Requirements" section of this MD&A.

Dividend Increases: Dividends paid per common share increased to $1.725 in 2018. In the fourth quarter of 2018 Fortis increased its quarterly dividend per common share by 5.9% to $0.45 per quarter, or $1.80 on an annualized basis. This continues the Corporation's track record of raising its annualized dividend to common shareholders for 45 consecutive years.

Fortis also extended its dividend guidance, targeting average annual dividend per common share growth of 6% through 2023. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its $17.3 billion five-year capital expenditure program, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence.

SUMMARY FINANCIAL HIGHLIGHTS

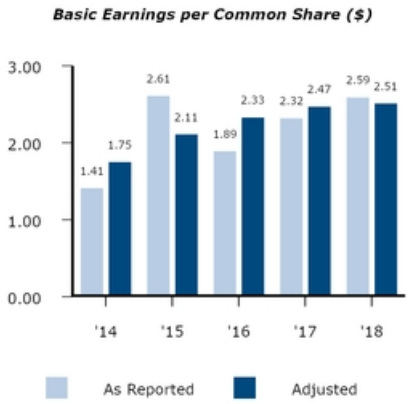
For the Years Ended December 31	**2018**	2017	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**1,100**	963	137
Basic Earnings per Common Share *($)*	**2.59**	2.32	0.27
Adjusted Basic Earnings per Common Share *($)* (1)	**2.51**	2.47	0.04
Weighted Average Number of Common Shares Outstanding *(millions)*	**424.7**	415.5	9.2
Cash Flow from Operating Activities *($ billions)*	**2.6**	2.8	(0.2)
Dividends Paid per Common Share *($)*	**1.725**	1.625	0.10
Total Assets *($ billions)*	**53.1**	47.8	5.3
Capital Expenditures *($ billions)*	**3.2**	3.0	0.2
Long-Term Debt Offerings *($ billions)*	**1.6**	2.5	(0.9)

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

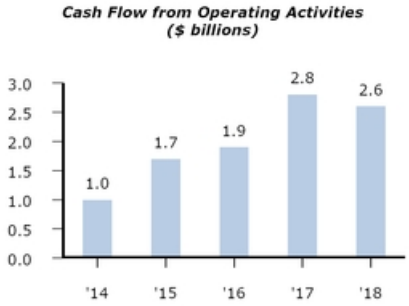
Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $1,100 million in 2018 compared to $963 million in 2017. The increase was driven by growth at both the regulated and non-regulated businesses, as well as lower income tax expense. The lower income tax expense primarily related to a one-time expense in 2017 associated with U.S. tax reform, along with the positive tax impacts of electing to file a consolidated state tax return and designating assets as held for sale in 2018. These increases were partially offset by a number of other distinct items recognized in 2017, including unrealized mark-to-market derivative gains, an acquisition break fee, and an unrealized foreign exchange gain on an affiliate loan. Earnings in 2018 were also tempered by the ongoing impact of U.S. tax reform, effective January 1, 2018, and a lower ROE incentive adder at ITC, effective April 2018.

Basic Earnings per Common Share: Basic earnings per common share were $2.59 in 2018 compared to $2.32 in 2017. The impact of higher net earnings attributable to common equity shareholders was partially offset by an increase in the weighted average number of common shares outstanding, primarily associated with the Corporation's dividend reinvestment plan.

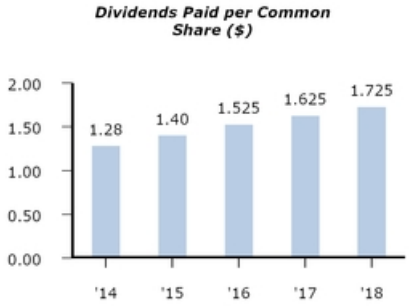
Adjusted Earnings per Common Share: Adjusted earnings per share were $2.51 in 2018, up $0.04 from 2017. The increase was driven by rate base growth at the regulated subsidiaries, strong performance at Aitken Creek and a lower effective income tax rate. The increase was partially offset by the ongoing impact of U.S. tax reform, an increase in the weighted average number of common shares outstanding, as discussed above, and the impact of a reduced ROE incentive adder at ITC.



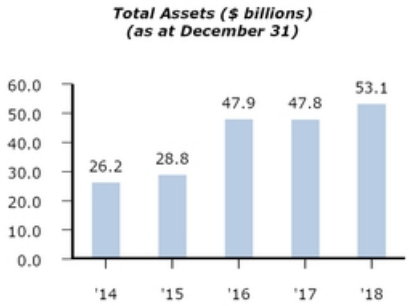
Cash Flow from Operating Activities: Cash flow from operating activities was $2.6 billion for 2018, a decrease of $0.2 billion compared to 2017. The decrease in cash provided by operating activities was primarily due to lower cash earnings, driven by ITC as a result of U.S. tax reform, and unfavourable changes in long-term regulatory deferrals.



Dividends: Dividends paid per common share increased to $1.725 in 2018, 5.9% higher than $1.625 in 2017. During the fourth quarter of 2018 Fortis increased its quarterly dividend per common share by 5.9% to $0.45.



Total Assets: Total assets increased approximately 11% to $53.1 billion at the end of 2018 compared to $47.8 billion at the end of 2017. The growth was due to continued investment in energy infrastructure at the regulated utilities as well as favourable foreign exchange on the translation of US dollar-denominated assets.



Capital Expenditures: Consolidated capital expenditures were $3.2 billion in 2018 compared to $3.0 billion in 2017. Total spending for 2018 was consistent with the forecast in the prior year's MD&A. For a detailed discussion of the Corporation's consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Long-Term Capital: The Corporation's regulated utilities raised approximately $1.6 billion in long-term debt in 2018, largely in support of capital investment and regularly scheduled debt repayments.

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)*	**2018**	2017	Variance
Revenue	**8,390**	8,301	89
Energy Supply Costs	**2,495**	2,361	134
Operating Expenses	**2,287**	2,250	37
Depreciation and Amortization	**1,243**	1,179	64
Other Income, Net	**60**	116	(56)
Finance Charges	**974**	914	60
Income Tax Expense	**165**	588	(423)
Net Earnings	**1,286**	1,125	161
Net Earnings Attributable to:			
Non-Controlling Interests	**120**	97	23
Preference Equity Shareholders	**66**	65	1
Common Equity Shareholders	**1,100**	963	137
Net Earnings	**1,286**	1,125	161
Basic Earnings per Common Share	**2.59**	2.32	0.27

Revenue
The increase in revenue was primarily due to higher electricity sales, driven by an increase in system capacity at UNS Energy, and the flow through in customer rates of higher overall commodity costs. The increase was partially offset by: (i) the recovery of lower income tax expense due to U.S. tax reform, which reduced the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018; (ii) mark-to-market accounting adjustments for natural gas derivatives at Aitken Creek, which resulted in an unrealized net loss of $10 million in 2018 compared to an unrealized net gain of $26 million in 2017; and (iii) a change in presentation of certain revenues to a net basis upon implementation of Accounting Standards Codification ("ASC") 606, *Revenue from Contracts with Customers,* in 2018.

Energy Supply Costs
The increase in energy supply costs was primarily due to overall higher commodity costs, driven by UNS Energy as a result of an increase in system capacity. This increase was partially offset by a lower cost of natural gas and lower gas sales volumes at FortisBC Energy.

Operating Expenses
The increase in operating expenses was primarily due to general inflationary and employee-related cost increases and the receipt of a $28 million break fee ($24 million net of related transaction costs and tax) associated with a terminated acquisition in 2017. The increase was partially offset by the corresponding change in presentation for revenue, as discussed above.

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

Other Income, Net
The decrease in other income, net of expenses, was primarily due to a one-time $21 million unrealized foreign exchange gain on a US dollar-denominated affiliate loan in 2017 and the favourable settlement of matters at UNS Energy pertaining to transmission refunds ordered by the Federal Energy Regulatory Commission ("FERC") in 2017. The decrease also reflects losses in 2018 on foreign exchange contracts and a lower equity component of allowance for funds used during construction ("AFUDC") at FortisBC Energy.

Finance Charges
The increase in finance charges was primarily due to overall higher debt levels to support capital expenditure programs.

Income Tax Expense
The decrease in income tax expense was driven by a lower effective income tax rate primarily due to U.S. tax reform. Also contributing to the decrease was the favourable impact of a one-time $30 million remeasurement of the Corporation's deferred income tax liabilities in 2018 that resulted from an election to file a consolidated state income tax return, and deferred income tax impacts related to assets held for sale.

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

The increase in net earnings attributable to common equity shareholders was driven by growth at both the regulated and non-regulated businesses, as well as lower income tax expense. The lower income tax expense primarily related to a one-time expense of $146 million in 2017 associated with U.S. tax reform, along with higher Corporate income tax recovery in 2018. The increase in income tax recovery was due to the remeasurement of deferred income tax liabilities as a result of an election to file a consolidated state income tax return and the deferred income tax impacts associated with assets held for sale.

These increases were partially offset by: (i) lower earnings associated with a $36 million unfavourable change in the mark-to-market of natural gas derivatives at Aitken Creek; (ii) higher Corporate expenses, primarily due to the receipt of an acquisition break fee, net of related transaction costs, of $24 million in 2017; (iii) a one-time $21 million unrealized foreign exchange gain on a US dollar-denominated affiliate loan in 2017; and (iv) FERC-ordered transmission refunds.

Earnings per common share were$0.27 higher year over year. The impact of the above-noted items on net earnings attributable to common equity shareholders was partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment plan.

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

Fortis uses two financial measures, adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share, that do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. These adjusting items may not be comparable with similar adjustments presented by other companies. The most directly comparable US GAAP measures are net earnings attributable to common equity shareholders and basic earnings per common share, respectively.

The Corporation calculates adjusted net earnings attributable to common equity shareholders as net earnings attributable to common equity shareholders plus or minus items that management excludes in its evaluation of the underlying operating performance of the business for the periods presented and to assist with the planning and forecasting of future operating results. In the fourth quarter of 2018, the Corporation decided to exclude the mark-to-market accounting adjustments related to the natural gas derivatives at Aitken Creek from its non-US GAAP measures as this item is excluded from management's evaluation of the underlying operating performance of the Energy Infrastructure segment. Adjusted basic earnings per common share is calculated by dividing adjusted net earnings attributable to common equity shareholders by the weighted average number of common shares outstanding.

A reconciliation of the non-US GAAP measures is provided below.

Non-US GAAP Reconciliation			
Years Ended December 31			
($ millions, except for common share data)	**2018**	2017	Variance
Net Earnings Attributable to Common Equity Shareholders	**1,100**	963	137
Adjusting Items:			
U.S. tax reform *(1)*	**—**	146	(146)
Unrealized loss (gain) on mark-to-market of derivatives *(2)*	**10**	(26)	36
Consolidated state income tax election *(3)*	**(30)**	—	(30)
Assets held for sale *(3)*	**(14)**	—	(14)
Acquisition break fee *(4)*	**—**	(24)	24
Unrealized foreign exchange gain *(5)*	**—**	(21)	21
FERC-ordered transmission refunds *(6)*	**—**	(11)	11
Adjusted Net Earnings Attributable to Common Equity Shareholders	**1,066**	1,027	39
Adjusted Basic Earnings per Common Share *($)*	**2.51**	2.47	0.04
Weighted Average Number of Common Shares Outstanding *(millions)*	**424.7**	415.5	9.2

(1) One-time remeasurement of deferred income tax assets and liabilities resulting from U.S. tax reform (ITC - $91 million, UNS Energy - $5 million, Central Hudson - $2 million, and Corporate and Other - $48 million)
(2) Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, included in the Energy Infrastructure segment
(3) Remeasurement of deferred income tax liabilities, included in the Corporate and Other segment
(4) Related to a terminated acquisition, included in the Corporate and Other segment
(5) One-time foreign exchange gain on an affiliate loan, included in the Corporate and Other segment
(6) Favourable settlement of matters at UNS Energy related to prior period FERC filings

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders			
Years Ended December 31			
($ millions)	**2018**	2017	Variance
Regulated Utilities			
ITC	**361**	272	89
UNS Energy	**293**	270	23
Central Hudson	**74**	70	4
FortisBC Energy	**155**	154	1
FortisAlberta	**120**	120	—
FortisBC Electric	**56**	55	1
Other Electric	**105**	98	7
Non-Regulated			
Energy Infrastructure	**72**	94	(22)
Corporate and Other	**(136)**	(170)	34
Net Earnings Attributable to Common Equity Shareholders	**1,100**	963	137

A discussion of the financial results of the Corporation's reporting segments follows. A discussion of the significant regulatory decisions and applications pertaining to the Corporation's 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. In2018 earnings from regulated utilities represented approximately 94% (2017 – 92%) of the Corporation's earnings from its operating segments, excluding Corporate and Other segment expenses. Total regulated utility assets represented approximately 97% of the Corporation's total assets as at December 31, 2018 (December 31, 2017 – 97%).

ITC

Financial Highlights *(1)*			
Years Ended December 31	**2018**	2017	Variance
Average US:CAD Exchange Rate *(2)*	**1.30**	1.30	—
Revenue *($ millions)*	**1,504**	1,575	(71)
Earnings *($ millions)*	**361**	272	89

(1) Revenue represents 100% of ITC, while earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflects consolidated purchase price accounting adjustments.
(2) The reporting currency of ITC is the US dollar.

Revenue
The decrease in revenue was primarily due tothe recovery of lower corporate income tax in customer rates associated with U.S. tax reform, partially offset by the impact of rate base growth and an increase in expenses recovered through customer rates.

Earnings
The increase in earnings was primarily due to a one-time $91 million deferred income tax expense in 2017 associated with U.S. tax reform. Also contributing to the increase was rate base growth, partially offset by the net unfavourable impact of U.S. tax reform in 2018 that resulted in holding company interest being deducted at a lower corporate tax rate.

UNS ENERGY

Financial Highlights			
Years Ended December 31	**2018**	2017	Variance
Average US:CAD Exchange Rate *(1)*	**1.30**	1.30	—
Electricity Sales *(gigawatt hours ("GWh"))*	**17,406**	14,971	2,435
Gas Volumes *(petajoules ("PJ"))*	**13**	13	—
Revenue *($ millions)*	**2,202**	2,080	122
Earnings *($ millions)*	**293**	270	23

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

Electricity Sales & Gas Volumes
The increase in electricity sales was primarily a result of an increase in short-term wholesale sales due to an increase in system capacity related to the lease of Gila River generating station Unit 2. Short-term wholesale revenues are primarily returned to customers through regulatory deferral mechanisms and, as a result, do not have an impact on earnings.

Gas volumes were comparable with 2017.

Revenue
The increase in revenue was primarily due to higher electricity sales as discussed above, the flow through of higher energy supply costs and the impact of the rate case settlement effective February 27, 2017, partially offset by the recovery of lower corporate income tax in customer rates in 2018 associated with U.S. tax reform.

Earnings
The increase in earnings was primarily due to lower income tax expense associated with U.S. tax reform and the impact of the rate case settlement as discussed above, partially offset by increased depreciation and amortization expense.

CENTRAL HUDSON

Financial Highlights			
Years Ended December 31	**2018**	2017	Variance
Average US:CAD Exchange Rate *(1)*	**1.30**	1.30	—
Electricity Sales *(GWh)*	**5,118**	4,891	227
Gas Volumes *(PJ)*	**24**	22	2
Revenue *($ millions)*	**924**	872	52
Earnings *($ millions)*	**74**	70	4

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

Electricity Sales & Gas Volumes
The increase in electricity sales and gas volumes was primarily due to higher average consumption as a result of colder temperatures increasing heating load during the winter months and warmer temperatures increasing air conditioning load during the summer months.

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

Revenue
The increase in revenue was primarily due to the recovery of higher commodity costs from customers and increases in customer delivery rates effective July 1, 2017 and 2018, partially offset by the recovery of lower corporate income tax in customer rates in 2018 associated with U.S. tax reform.

Earnings
The increase in earnings was primarily due to the rate increases effective July 1, 2017 and 2018 reflecting a return on increased rate base assets, partially offset by storm restoration costs.

FORTISBC ENERGY

Financial Highlights			
Years Ended December 31	**2018**	2017	Variance
Gas Volumes *(PJ)*	**212**	221	(9)
Revenue *($ millions)*	**1,187**	1,198	(11)
Earnings *($ millions)*	**155**	154	1

Gas Volumes
The decrease in gas volumes was primarily due to lower average consumption as a result of warmer temperatures reducing heating load in the first half of 2018 and focused customer conservation efforts in the fourth quarter relating to reduced gas supply.

Revenue
The decrease in revenue was primarily due to lower commodity cost of natural gas charged to customers, partially offset by rate base growth.

Earnings
Earnings were consistent year over year as the impact of rate base growth was largely offset by the recognition of AFUDC during 2017 associated with the Tilbury liquified natural gas ("LNG") facility expansion.

FortisBC Energy earns approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulatory deferral mechanisms, changes in consumption levels and the cost of natural gas do not materially affect earnings.

FORTISALBERTA

Financial Highlights			
Years Ended December 31	**2018**	2017	Variance
Energy Deliveries *(GWh)*	**17,154**	17,018	136
Revenue *($ millions)*	**579**	600	(21)
Earnings *($ millions)*	**120**	120	—

Energy Deliveries
The increase in energy deliveries was primarily due to higher average consumption as a result of colder temperatures increasing heating load in winter months and warmer temperatures increasing air conditioning load in summer months, as well as higher farm and irrigation consumption due to lower precipitation. Customer additions also contributed to higher energy deliveries.

Revenue
An election to record municipal franchise fee revenue on a net basis upon implementation of ASC 606,*Revenue from Contracts with Customers*, effective January 1, 2018, using the modified retrospective approach under which comparative periods are not restated, resulted in a decrease in revenue of approximately $43 million. This decrease was partially offset by higher distribution rates effective January 1, 2018, reflecting a return on increased rate base assets and incremental return due to efficiencies achieved in the first PBR term through an efficiency carryover mechanism, and revenue associated with customer additions.

Earnings
Earnings were consistent as the increase associated with higher revenue, as discussed above, was offset by higher operating expenses related to vegetation management and costs associated with a voluntary retirement program completed in the fourth quarter of 2018, as well as increased interest expense associated with the issuance of long-term debt in September 2017.

FORTISBC ELECTRIC

Financial Highlights			
Years Ended December 31	**2018**	2017	Variance
Electricity Sales *(GWh)*	**3,250**	3,305	(55)
Revenue *($ millions)*	**408**	398	10
Earnings *($ millions)*	**56**	55	1

Electricity Sales
The decrease in electricity sales was due to lower average consumption primarily due to warmer winter temperatures reducing heating load in 2018.

Revenue
The increase in revenue was primarily due to an increase in revenue recognized from third-party contract work and higher surplus power sales, partially offset by the flow through of lower overall expenses in customer rates and lower electricity sales.

Earnings
Earnings were comparable with 2017, with the slight increase primarily due to rate base growth.

Variances from regulated forecasts used to set rates for electricity revenue and energy supply costs are flowed through to customers in future rates through approved regulatory deferral mechanisms and, therefore, do not have an impact on earnings.

OTHER ELECTRIC

Financial Highlights			
Years Ended December 31	**2018**	2017	Variance
Average USD:CAD Exchange Rate *(1)*	**1.30**	1.30	—
Electricity Sales *(GWh)*	**9,292**	9,196	96
Revenue *($ millions)*	**1,412**	1,363	49
Earnings *($ millions)*	**105**	98	7

(1) The reporting currency of Caribbean Utilities and FortisTCI is the US dollar. The reporting currency of BEL is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Electricity Sales
The increase in electricity sales was due to overall higher average consumption related to heating load in winter months and air conditioning load in summer months, increased number of customers, and a recovering economy on the Turks and Caicos Islands following the impact of Hurricane Irma in 2017.

Revenue
The increase in revenue was primarily due to the flow through in customer rates of higher fuel costs in the Caribbean and higher electricity sales.

Earnings
The increase in earnings was primarily due to the receipt of FortisTCI's business interruption insurance proceeds in 2018, higher electricity sales, and business development costs of approximately $2 million incurred in 2017 related to the Wataynikaneyap Transmission Power Project, partially offset by lower equity income from BEL.

NON-REGULATED

ENERGY INFRASTRUCTURE

Financial Highlights			
Years Ended December 31	**2018**	2017	Variance
Energy Sales *(GWh)*	**853**	889	(36)
Revenue *($ millions)*	**184**	226	(42)
Earnings *($ millions)*	**72**	94	(22)

Energy Sales
The decrease in energy sales was primarily due to lower rainfall reducing hydroelectric production in Belize.

Revenue and Earnings
The decrease in revenue and earnings was primarily due to the unfavourable impact of the mark-to-market accounting of natural gas derivatives at Aitken Creek, with unrealized losses of $10 million during 2018 compared to unrealized gains of $26 million during 2017. Revenue and earnings were also impacted by favourable pricing of natural gas at Aitken Creek during the first half of 2018, partially offset by lower hydroelectric production in Belize.

Aitken Creek is subject to commodity price risk, as it purchases and holds natural gas in storage to earn a profit margin from its ultimate sale. Aitken Creek mitigates this risk by using derivatives to substantially lock in the profit margin that will be realized upon the sale of natural gas. The fair value accounting of these derivatives creates timing differences and the resultant earnings volatility can be significant from period to period.

CORPORATE AND OTHER

Financial Highlights Years Ended December 31 *($ millions)*	**2018**	2017	Variance
Net Loss	**(136)**	(170)	34

The decrease in net loss was primarily driven by higher income tax recovery due to: (i) deferred income tax expense of $48 million in 2017 associated with U.S. tax reform; (ii) a remeasurement of deferred income tax liabilities of $30 million in 2018 associated with an election to file a consolidated state income tax return; and (iii) the remeasurement of deferred income tax liabilities of $14 million associated with assets held for sale. The increase in income tax recovery was partially offset by: (i) the 2018 impact of U.S. tax reform, which resulted in holding company interest being deductible at a lower corporate tax rate; (ii) the receipt of a $24 million break fee associated with a terminated acquisition in 2017; (iii) a $21 million unrealized foreign exchange gain on a US-dollar denominated affiliate loan in 2017; and (iv) losses in 2018 on foreign exchange contracts, partially offset by lower stock-based compensation year over year.

REGULATORY HIGHLIGHTS

The following summarizes the significant regulatory decisions and applications pertaining to the Corporation's regulated utilities for2018.

ITC

Incentive Adder Complaint
In April 2018 a third-party complaint was filed with FERC challenging the independence incentive adders that are included in transmission rates charged by transmission owners operating in the Midcontinent Independent System Operator ("MISO") region, which includes ITCTransmission, METC and ITC Midwest (collectively "ITC's MISO Subsidiaries"). The adder allowed up to 0.50% or 1.00% to be added to the authorized ROE, subject to any ROE cap established by FERC. In October 2018 FERC issued an order reducing the adders to 0.25%, effective April 20, 2018. This equates to a 0.25% decrease in ROE, down from the approximate 0.50% that ITC was earning in rates previously approved by FERC. ITC's MISO Subsidiaries sought rehearing of this order and began reflecting the 0.25% adder in transmission rates in November 2018. Refunds began in the fourth quarter of 2018 and were completed in the first quarter of 2019. The order is not expected to have a material impact on the Corporation's earnings or cash flows.

ROE Complaints
Two third-party complaints requested that the base ROE for MISO transmission owners, including ITC's MISO Subsidiaries, be found to no longer be just or reasonable. The complaints cover two consecutive 15-month periods from November 2013 through February 2015 (the "Initial Refund Period" or "Initial Complaint") and February 2015 through May 2016 (the "Second Refund Period" or "Second Complaint"). FERC orders on the complaints will also set the ROE that will be effective prospectively from the order dates.

In September 2016 FERC ordered that the base ROE for the Initial Refund Period be set at 10.32%, down from 12.38%, with a maximum of 11.35%. The resultant rates apply prospectively from September 2016 until an approved ROE is established for the Second Refund Period. The MISO transmission owners sought rehearing of this order. The total refund for the Initial Complaint as a result of the September 2016 FERC order was $158 million (US$118 million), including interest, and was paid in 2017.

In June 2016 the presiding Administrative Law Judge ("ALJ") issued an initial decision on the Second Complaint, recommending a base ROE of 9.70%, with a maximum of 10.68%. The initial decision of the ALJ is a non-binding recommendation to FERC, and FERC has yet to issue its order on the Second Complaint. In September 2017 certain MISO transmission owners filed a motion for FERC to dismiss the Second Complaint. Pending an order from FERC, an estimated regulatory liability of $206 million (US$151 million) has been recognized (December 31, 2017 - $182 million (US$145 million)).

There is uncertainty regarding the final outcome of the Initial and Second Complaints due in part to a November 2018 FERC order proposing a new methodology for determining a just and reasonable base ROE. Fortis considers the new methodology to be generally constructive for transmission owners. If finalized, this proposed methodology will be used to address ITC's outstanding ROE complaints. Briefs are due to be filed in the first half of 2019 on the proposed adoption of the new methodology.

Central Hudson

General Rate Application

In June 2018 the New York Public Service Commission ("PSC") issued an order approving a three-year rate plan, or joint proposal, that had been filed by Central Hudson along with multiple stakeholders and intervenors, pursuant to the July 2017 general rate application. The order included an allowed ROE of 8.8% and common equity ratios of 48%, 49% and 50% in rate years one, two and three, respectively, and is effective July 1, 2018 through June 30, 2021. Also included is an earnings sharing mechanism whereby the Company and its customers share equally earnings between 50 and 100 basis points above the allowed ROE. Earnings beyond this are primarily returned to customers.

FortisAlberta

Generic Cost of Capital

Pursuant to generic cost of capital proceedings completed in 2018, FortisAlberta's rates reflect an allowed ROE of 8.5% on a capital structure of 37% common equity for 2018-2020, unchanged from 2017.

In December 2018 the AUC initiated a proceeding to consider establishing a formula-based approach to setting the approved ROE beginning for the year 2021, and to consider whether any process changes are necessary for determining capital structure in years in which the ROE formula is in place.

U.S. Tax Reform

In 2018 the Corporation's U.S. utilities worked with their respective regulators to return to customers the net income tax savings resulting from U.S. tax reform.

ITC: In April 2018 ITC's MISO Subsidiaries reposted formula rates charged to customers retroactive to January 1, 2018, as approved by FERC. As at December 31, 2018, the amounts owing had been returned to customers.

UNS Energy: In April 2018 the Arizona Corporation Commission approved TEP's application to return ongoing income tax savings through a combination of customer bill credits and regulatory liabilities. Customer bill credits became effective in May 2018. As at December 31, 2018, the amounts owing had been substantially returned to customers. In 2019 and beyond, TEP will continue to return savings to customers using the same approach. Regulatory liabilities will be returned to customers as part of TEP's next rate case, which is expected to be filed in 2019.

In March 2018 FERC issued an order directing TEP to either: (i) submit proposed revisions to its transmission rates or transmission revenue requirement to reflect the reduction in the federal corporate income tax rate; or (ii) show why a rate adjustment is not required. In May 2018 TEP proposed an overall customer rate reduction, to be effective March 2018, reflecting the lower federal corporate income tax rate. FERC approved the proposal, effective March 21, 2018.

Central Hudson: In June 2018, as part of its approval of the joint proposal discussed above, the PSC approved Central Hudson's recommendation to reflect the recovery of lower federal corporate income tax in customer rates, effective July 1, 2018. As at December 31, 2018, $14 million (US$10 million) was deferred for the future benefit of customers related to the income tax savings realized in the first six months of 2018.

Significant Regulatory Proceedings

The following table summarizes significant upcoming regulatory proceedings with the related filings expected in 2019.

Regulated Utility	Application/Proceeding
TEP	Targeted Rate Case Filing
FBC Energy and FBC Electric	Targeted 2020-2024 Multi-Year Rate Plan Filing

CONSOLIDATED FINANCIAL POSITION

Significant Changes in the Consolidated Balance Sheets between December 31, 2018 and December 31, 2017

Balance Sheet Account	Increase ($ millions) [1]	Explanation
Accounts receivable and other current assets	226	The increase was mainly due to higher income tax receivable, higher wholesale sales at UNS Energy and foreign exchange.
Assets held for sale	766	The increase was due to a reclassification, primarily from property, plant and equipment, of the assets associated with the expected sale of the Corporation's 51% interest in the Waneta Expansion.
Regulatory assets (including current and long-term)	133	The increase was primarily due to foreign exchange and higher deferred income taxes at FortisAlberta, partially offset by the regulator-ordered netting of certain regulatory liabilities at Central Hudson.
Property, plant and equipment, net	2,986	The increase was mainly due to capital expenditures, foreign exchange and the recognition of a capital lease for Gila River generating station Unit 2 at UNS Energy. The increase was partially offset by depreciation and the reclassification of assets held for sale.
Intangible assets, net	119	The increase was primarily due to foreign exchange and ITC expenditures related to land rights and software.
Goodwill	886	The increase was due to foreign exchange.
Accounts payable and other current liabilities	236	The increase was mainly due to higher amounts owing for energy supply costs and foreign exchange, partially offset by the timing of transmission cost payments at FortisAlberta.
Regulatory liabilities (including current and long-term)	180	The increase was primarily due to foreign exchange, partially offset by lower rate stabilization accounts at FortisBC Energy.
Deferred income tax liabilities	388	The increase was mainly due to timing differences related to capital expenditures at the regulated utilities, foreign exchange and the utilization of taxable losses.
Long-term debt (including current portion and short-term borrowings)	2,540	The increase was due to debt issuances at the regulated utilities, foreign exchange and higher net borrowings under committed credit facilities, partially offset by scheduled debt repayments.
Capital lease and finance obligations (including current portion)	181	The increase was mainly due to UNS Energy's recognition of a capital lease for Gila River generating station Unit 2.
Shareholders' equity	1,530	The increase was due to: (i) accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common shareholders for 2018, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment plan.
Non-controlling interests	177	The increase was due to net earnings and comprehensive income attributable to minority interests.

(1) Includes the impact of foreign exchange based upon the closing foreign exchange rate at December 31, 2018 of US$1.00=CAD$1.36 compared to the closing foreign exchange rate at December 31, 2017 of US$1.00=CAD$1.25.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CONSOLIDATED CASH FLOWS

The Corporation's sources and uses of cash are provided below.

Summary of Consolidated Cash Flows			
Years ended December 31			
($ millions)	**2018**	2017	Variance
Cash, Beginning of Year	**327**	269	58
Cash Provided by (Used in):			
Operating Activities	**2,604**	2,756	(152)
Investing Activities	**(3,252)**	(3,025)	(227)
Financing Activities	**644**	339	305
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**24**	(12)	36
Cash Associated with Assets Held for Sale	**(15)**	—	(15)
Cash, End of Year	**332**	327	5

Operating Activities:
The decrease in cash provided by operating activities was primarily due to lower cash earnings, driven primarily by ITC as a result of U.S. tax reform, and unfavourable changes in long-term regulatory deferrals. Long-term regulatory deferrals decreased mainly due to the deferral of higher gas storage and transportation costs at FortisBC Energy related to a gas pipeline incident in the fourth quarter of 2018, and the funding of clean energy initiatives and the deferral of major storm costs at Central Hudson.

Investing Activities:
The increase in cash used in investing activities was due to higher capital spending.

Financing Activities:
The increase in cash provided by financing activities was primarily due to lower net repayments of credit facilities and short-term borrowings and lower repayments of long-term debt mainly at the Corporation's regulated utilities. The increase was partially offset by lower proceeds from the issuance of long-term debt at the Corporation's regulated utilities, driven by ITC.

In 2017 approximately 12.2 million common shares of Fortis were issued to an institutional investor for proceeds of $500 million. The net proceeds were used to repay credit facility borrowings related to the financing of the ITC acquisition.

Proceeds from long-term debt, net of issue costs, are summarized below.

Proceeds from Long-Term Debt, Net of Issue Costs			
Years ended December 31			
($ millions)	**2018** *(1)*	2017	Variance
ITC	**516**	1,863	(1,347)
UNS Energy	**390**	—	390
Central Hudson	**136**	74	62
FortisBC Energy	**198**	173	25
FortisAlberta	**149**	199	(50)
FortisBC Electric	**—**	74	(74)
Other Electric	**177**	155	22
Total	**1,566**	2,538	(972)

(1) Refer to Note 16 of the 2018 Annual Financial Statements for issue date, form of instrument, interest rate, term and use of proceeds.

In January 2019 ITC issued 30-year US$50 million secured notes at 4.55%. ITC will have an additional US$50 million delayed draw of 30-year secured notes at 4.65% in July 2019. The net proceeds will be used to repay credit facility borrowings, finance capital expenditures and for general corporate purposes.

Borrowings under credit facilities by the utilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility.

Common share dividends paid in 2018 totalled $459 million, net of $272 million of dividends reinvested, compared to $419 million, net of $253 million of dividends reinvested, paid in 2017. 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 $1.725 in 2018 compared to $1.625 in 2017. The weighted average number of common shares outstanding was 424.7 million for 2018 compared to 415.5 million for 2017.

CONTRACTUAL OBLIGATIONS

Contractual obligations with external third parties in each of the next five years and for periods thereafter, as at December 31, 2018, are as follows.

Contractual Obligations **As at December 31, 2018** *($ millions)*	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Long-term debt	**24,231**	926	731	1,324	1,125	1,605	18,520
Interest obligations on long-term debt	**16,345**	994	973	950	902	870	11,656
Capital lease and finance obligations *(1)*	**2,451**	313	77	80	49	47	1,885
Power purchase obligations *(2)*	**2,438**	254	191	174	170	172	1,477
Renewable power purchase obligations *(3)*	**1,699**	110	110	109	109	108	1,153
Gas purchase obligations *(4)*	**1,348**	359	290	242	202	144	111
Long-term contracts - UNS Energy *(5)*	**777**	176	142	92	60	46	261
ITC easement agreement *(6)*	**436**	14	14	14	14	14	366
Renewable energy credit purchase agreements *(7)*	**146**	24	26	18	11	11	56
Debt collection agreement *(8)*	**119**	3	3	3	3	3	104
Purchase of Springerville Common Facilities *(9)*	**93**	—	—	93	—	—	—
Waneta Partnership promissory note	**72**	72	—	—	—	—	—
Joint-use asset and shared service agreements	**52**	3	3	3	3	3	37
Operating lease obligations	**51**	8	6	5	4	4	24
Other *(10)*	**530**	108	84	89	38	36	175
Total	**50,788**	3,364	2,650	3,196	2,690	3,063	35,825

(1) Includes principal payments, imputed interest and executory costs.

(2) The most significant power purchase obligations are described below.

Maritime Electric ($771 million): includes an agreement entitling Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and requiring Maritime Electric to pay its share of the station's capital operating costs for the life of the unit. Maritime Electric also has two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2024.

FortisOntario ($705 million): an agreement with Hydro-Québec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through December 2030.

FortisBC Energy ($522 million): an agreement with BC Hydro for the supply of electricity to the Tilbury LNG facility expansion.

FortisBC Electric ($345 million): includes an agreement with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013.

(3) TEP and UNS Electric are party to renewable PPAs, with expiry dates from 2027 through 2043, that require them to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. Amounts shown are the estimated future payments.

(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, 2018.

(5) UNS Energy enters into long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, and the purchase of transmission services for purchased power. Amounts paid for coal depend on actual quantities purchased and delivered. Certain contracts have price adjustment clauses that will affect future costs. These contracts have various expiry dates between 2019 and 2040.

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

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

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

(9) UNS Energy is obligated to purchase an undivided32.2% interest in the Springerville Common Facilities if the related two leases are not renewed. The initial lease terms expire in January 2021.

(10) Includes stock-based compensation plan obligations, land easements, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Their capital expenditures are largely to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. Consolidated capital expenditures are forecast to be approximately $3.7 billion for 2019 and approximately $17.3 billion over the five-year period from 2019 through 2023.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling $2.3 billion (US$1.7 billion). Central Hudson's maximum commitment is $248 million (US$182 million), for which it has issued a parental guarantee. As at December 31, 2018, there was no obligation under this guarantee.

As at December 31, 2018, FHI had $77 million (December 31, 2017 - $80 million) of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

CAPITAL STRUCTURE

The Corporation's utilities require ongoing access to capital to fund maintenance and expansion of infrastructure. Fortis raises debt at the utility level to ensure regulatory transparency, tax efficiency and financing flexibility. 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 its customer rates.

The consolidated capital structure of Fortis is presented below.

Capital Structure		
As at December 31		
(%)	**2018**	2017
Debt *(1)*	**57.0**	56.5
Preference shares	**3.8**	4.2
Common shareholders' equity and minority interest	**39.2**	39.3
Total	**100.0**	100.0

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

The capital structure was impacted by: (i) an increase in long-term debt to fund energy infrastructure investment and foreign exchange on the translation of US dollar-denominated debt, partially offset by scheduled debt repayments; (ii) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (iii) the issuance of common shares under the Corporation's dividend reinvestment plan; and (iv) net earnings attributable to common equity shareholders for 2018, less dividends declared on common shares.

CREDIT RATINGS

As at December 31, 2018, the Corporation's credit ratings were as follows.

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

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and the level of debt at the holding company.

In March 2018 S&P affirmed the Corporation's credit ratings and revised its outlook from stable to negative due to a modest temporary weakening of financial measures as a result of U.S. tax reform, which reduces cash flow at the Corporation's U.S. regulated utilities.

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.

Consolidated capital expenditures for 2018 were approximately $3.2 billion and a breakdown by segment and asset category is as follows.

Consolidated Capital Expenditures *(1)*
Year Ended December 31, 2018

	Regulated Utilities									
($ millions)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated** *(2)*	**Total**
Generation	—	182	1	—	—	26	64	**273**	**30**	**303**
Transmission	916	58	32	230	—	17	41	**1,294**	**—**	**1,294**
Distribution	—	235	157	183	370	46	160	**1,151**	**—**	**1,151**
Other *(3)*	82	124	55	73	63	17	35	**449**	**21**	**470**
Total	998	599	245	486	433	106	300	**3,167**	**51**	**3,218**

(1) Represents cash payments to construct property, plant and equipment and intangible assets, as reflected on the consolidated statement of cash flows
(2) Includes Energy Infrastructure and Corporate and Other segments
(3) Includes facilities, equipment, vehicles, information technology and other, along with capital expenditures associated with Alberta Electric System Operator ("AESO") transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast. Consolidated capital expenditures of $3.2 billion for 2018 were consistent with the forecast, as disclosed in the MD&A for the year ended December 31, 2017.

Consolidated capital expenditures for 2019 are expected to be approximately $3.7 billion and a breakdown by segment and asset category is as follows.

Forecast Consolidated Capital Expenditures *(1)*
Year Ending December 31, 2019

	Regulated Utilities									
($ millions)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated** *(2)*	**Total**
Generation	—	406	3	—	—	29	53	**491**	**2**	**493**
Transmission	798	320	36	267	—	25	198	**1,644**	**—**	**1,644**
Distribution	—	245	163	141	311	43	137	**1,040**	**—**	**1,040**
Other *(3)*	67	105	78	95	103	19	30	**497**	**26**	**523**
Total	865	1,076	280	503	414	116	418	**3,672**	**28**	**3,700**

(1) Represents forecast cash payments to construct property, plant and equipment and intangible assets, as would be reflected on the consolidated statement of cash flows, as well as Fortis' assumed share of estimated capital spending for the Wataynikaneyap Transmission Power Project. Forecast capital expenditures for 2019 are based on a forecast exchange rate of US$1.00=CAD$1.28. Based on the closing foreign exchange rate on December 31, 2018 of US$1.00=CAD$1.36, forecast capital expenditures for 2019 would be approximately $3.9 billion.
(2) Includes Energy Infrastructure and Corporate and Other segments
(3) Includes facilities, equipment, vehicles, information technology and other, along with forecast capital expenditures associated with AESO transmission-related investment at FortisAlberta

The percentage breakdown of 2018 actual and 2019 forecast consolidated capital expenditures among growth, sustaining and other is as follows.

Consolidated Capital Expenditures

Year Ending December 31	**Actual**	Forecast
(%)	**2018**	2019
Growth *(1)*	**34**	31
Sustaining *(2)*	**52**	56
Other *(3)*	**14**	13
Total	**100**	100

(1) Capital expenditures to connect new customers and infrastructure upgrades required to meet customer and associated load growth, including capital expenditures associated with AESO transmission-related investment at FortisAlberta
(2) Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation, transmission and distribution assets
(3) Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period from 2019 through 2023 ("five-year capital program"), consolidated capital expenditures are expected to be approximately $17.3 billion, $2.8 billion higher than $14.5 billion previously forecast for the period from 2018 through 2022, as disclosed in the MD&A for the year ended December 31, 2017. The increase in the five-year capital program is the result of the Corporation's sustainable organic growth platform, the inclusion of Fortis' assumed share of estimated capital investment for the Wataynikaneyap Transmission Power Project, and increased investment in grid modernization, renewables, and natural gas infrastructure primarily at ITC, UNS Energy and FortisBC Energy, respectively. The low-risk, highly executable five-year capital program is virtually all occurring at the regulated utilities and contains only a small number of major projects.

The approximate breakdown of the capital spending expected to be incurred is as follows: 55% in the U.S., including 26% at ITC; 42% in Canada; and the remaining 3% in the Caribbean. 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: 28% to meet customer growth; 60% for sustaining capital expenditures; and 12% for facilities, equipment, vehicles, information technology and other assets.

The five-year capital program is expected to be primarily funded with cash from operations, debt raised at the utilities and common equity from the Corporation's dividend reinvestment plan. The remaining funds are expected to be generated from the sale of the Waneta Expansion in 2019. The Corporation's at-the-market common equity program will also be available to provide further financing flexibility, if needed.

Actual 2018 and forecast 2019 midyear rate base for the Corporation's regulated utilities is as follows.

Midyear Rate Base *(1)*	**Actual**	Forecast
($ billions)	**2018**	2019
ITC	**7.8**	8.5
UNS Energy	**4.7**	5.3
Central Hudson	**1.6**	1.8
FortisBC Energy	**4.4**	4.5
FortisAlberta	**3.4**	3.6
FortisBC Electric	**1.3**	1.3
Other Electric	**2.9**	2.9
Total	**26.1**	27.9

(1) Actual midyear rate base for 2018 is based on the actual average exchange rate of US$1.00=CAD$1.30 and forecast midyear rate base for 2019 is based on a forecast exchange rate of US$1.00=CAD$1.28. Based on the closing foreign exchange rate on December 31, 2018 of US$1.00=CAD$1.36, forecast midyear rate base for 2019 would be approximately $29 billion.

The most significant capital projects included in the five-year capital program are summarized below.

Significant Capital Projects *(1)*					Forecast	Expected
($ millions)		Pre-	**Actual**	Forecast	2020 -	Year of
Company	**Nature of Project**	2018	**2018**	2019	2023	Completion
ITC *(2) (3)*	Multi-Value Regional Transmission Projects ("MVPs")	370	**211**	88	244	2023
	34.5 to 69 kilovolt ("kV") Transmission Conversion Project	86	**139**	87	261	Post-2023
UNS Energy *(3)*	Gila River Natural Gas Generating Station Unit 2	—	**—**	211	—	2019
	Southline Transmission Project	—	**—**	182	207	2022
	New Mexico Wind Project	—	**—**	55	222	2020
FortisBC Energy	Lower Mainland Intermediate Pressure System Upgrade ("LMIPSU")	43	**165**	187	65	2020
	Eagle Mountain Woodfibre Gas Line Project *(4)*	—	**—**	—	350	2023
	Transmission Integrity Management Capabilities Project	—	**—**	—	568	Post-2023
	Inland Gas Upgrades Project	—	**3**	14	208	Post-2023
Wataynikaneyap	Transmission Power Project *(5)*	—	**25**	158	429	2023

(1) Represents property, plant and equipment and intangible asset expenditures, including both the capitalized debt and equity components of AFUDC, where applicable. Significant capital projects are identified as those with a total project cost of $150 million or greater and exclude ongoing capital maintenance projects.
(2) Capital expenditures prior to 2018 are from the date of acquisition of October 14, 2016.
(3) Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CAD$1.28 for 2019 through 2023.
(4) Net of forecast customer contributions
(5) Fortis' assumed share of estimated capital spending, including deferred development costs. Under the funding framework, Fortis will be funding its equity component only.

The MVPs at ITC consist of four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. Approximately $580 million (US$447 million) was invested in the MVPs from the date of acquisition of ITC, and an additional $332 million (US$259 million) is expected to be spent from 2019 through 2023. One of the MVPs was completed in 2018 and the remaining projects are in various stages of construction with in-service dates expected to range from 2019 through 2023.

The 34.5 to 69kV Transmission Conversion Project at ITC consists of multiple capital initiatives designed to construct and rebuild new 69-kV lines, with in-service dates ranging from 2019 to post-2023. Approximately $350 million (US$272 million) is expected to be invested in this project over the five-year period through 2023.

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

The Southline Transmission Project is a 600 MW transmission line designed to collect and transmit electricity across southern New Mexico and southern Arizona. UNS Energy expects to purchase a 250 MW ownership in the project. Construction is expected to commence in 2019, with completion expected in 2022. The capital cost of the project for UNS Energy is estimated at approximately $390 million (US$304 million). The transmission line will improve reliability in the region and facilitate the connection of renewable energy resources to the grid, including the New Mexico Wind Project.

The New Mexico Wind Project is a 750 MW wind power generating plant that will be interconnected to the Southline Transmission line and complements UNS Energy's existing renewable solar generation portfolio. UNS Energy will have a 150 MW ownership under a build-transfer asset contract, with an option to purchase additional ownership in the future. Construction is expected to commence in 2019, with completion expected in 2020. The capital cost of the project for UNS Energy is estimated at approximately $280 million (US$217 million).

The Lower Mainland System Upgrade project addresses system capacity and pipeline condition issues for the gas supply system in the Lower Mainland of British Columbia. The project is being completed in two phases: (i) the Coastal Transmission System ("CTS") phase, which increases security of supply; and (ii) the LMIPSU phase, which is focused on addressing pipeline condition issues. Construction activities for the CTS project are complete, and the new pipelines are in service. During the third quarter of 2018, a significant portion of the Vancouver section of the LMIPSU project was completed and was gasified in December. Construction of the remaining portion of the project has resumed in the first quarter of 2019. The total capital cost of both phases is estimated to be approximately $640 million, with approximately $250 million expected to be spent on the LMIPSU phase from 2019 through 2020. The final project costs remain subject to review by the British Columbia Utilities Commission ("BCUC") after the project is complete and in service.

The Eagle Mountain Woodfibre Gas Line Project is a pipeline expansion at a proposed LNG site in Squamish, British Columbia. The current estimate of FortisBC Energy's investment in the project may be updated for final scoping, detailed construction estimates and scheduling, and final determination of customer capital contributions. FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting this project from further regulatory approval by the BCUC. In the fourth quarter of 2018, FortisBC Energy and Woodfibre LNG Limited ("Woodfibre") entered into a pre-execution work agreement, which enables FortisBC Energy to incur project feasibility and development costs and establishes the funding requirements from Woodfibre during this phase. FortisBC Energy's anticipated capital expenditures, net of forecast customer contributions, is approximately $350 million and remains contingent on Woodfibre making a final investment decision. The project is expected to be in service in 2023.

The multi-year Transmission Integrity Management Capabilities Project is focused on improving gas line safety and the integrity of the transmission system, including gas line modifications and looping. The capital cost of the project is estimated at $570 million, an increase of approximately $260 million from the amount disclosed in the 2017 Annual MD&A. In December 2018 a regulatory deferral account was approved by the BCUC to capture approximately $40 million of development costs to be incurred in 2019 and 2020 to enable the filing of a Certificate of Public Convenience ("CPCN").

The multi-year Inland Gas Upgrades Project will involve gas line modifications and replacements enabling in-line inspection capabilities, a key tool to confirm the integrity of transmission gas lines. In December 2018 the CPCN application was filed with the BCUC and approval is expected in the second half of 2019. The total cost of the project is estimated to be $360 million, with $225 million expected to be invested over the five-year period through 2023. Subject to CPCN approval, construction of the project is expected to commence in 2020.

The Wataynikaneyap Transmission Power Project will connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid through the construction of 1,800 kilometres of transmission lines. Wataynikaneyap Power is a licensed transmission company, regulated by the Ontario Energy Board ("OEB"), equally owned by 24 First Nations communities (51%), in partnership with Fortis (39%) and Algonquin Power & Utilities Corp. (10%). In March 2018 the project reached a significant milestone with the formal announcement of a funding framework among Wataynikaneyap Power, the Government of Canada and the Government of Ontario. FortisOntario will be responsible for construction management and operation of the transmission line.

The total estimated capital cost for the Wataynikaneyap Transmission Power Project is approximately $1.6 billion. The initial phase of the project to connect the Pikangikum First Nation to Ontario's power grid was fully funded by the Canadian government and was completed in late 2018. The next two phases are subject to receipt of all necessary regulatory approvals, including the leave-to-construct approval from the OEB. The leave-to-construct application was filed with the OEB in June 2018 and approval is expected in the first half of 2019. These phases are targeted to be completed by the end of 2020 and 2023, respectively. In addition to providing participating First Nations communities ownership in the transmission line, the project provides socio-economic benefits, reduces environmental risk and lessens greenhouse gas emissions associated with diesel-fired generation currently used in remote locations.

ADDITIONAL INVESTMENT OPPORTUNITIES

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

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

In 2017 the project's major application process in the United States and Canada was completed upon receipt of permits from the U.S. Army Corps of Engineers. The project continues to advance through regulatory, operational and economic milestones. Ongoing activities include completing project cost refinements and securing favourable transmission service agreements with prospective counterparties. Pending achievement of key milestones, completion of the project would take approximately three years from the commencement of construction.

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

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

CASH FLOW REQUIREMENTS

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of operating cash flows, with varying levels of residual cash flows available for 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 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.

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

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

In December 2018 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 $2.5 billion during the 25-month life of the base shelf prospectus. In December 2018 the Corporation re-established its at-the-market common equity program that allows the issuance of up to $500 million of common shares from treasury to the public at the Corporation's discretion, effective until January 2021.

As at December 31, 2018, management expects consolidated fixed-term debt maturities and repayments to be $191 million in 2019 and to average approximately $929 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, 2018 and are expected to remain compliant in 2019.

CREDIT FACILITIES

As at December 31, 2018, the Corporation and its subsidiaries had consolidated credit facilities of approximately $5.2 billion, of which approximately $3.9 billion was unused, including $1.0 billion unused under the Corporation's committed revolving corporate credit facility.

The following summarizes the credit facilities of the Corporation and its subsidiaries.

Credit Facilities				
As at December 31 *($ millions)*	Regulated Utilities	Corporate and Other	**2018**	2017
Total credit facilities	3,780	1,385	**5,165**	4,952
Credit facilities utilized:				
Short-term borrowings	(60)	—	**(60)**	(209)
Long-term debt (including current portion) *(1)*	(731)	(335)	**(1,066)**	(671)
Letters of credit outstanding	(65)	(54)	**(119)**	(129)
Credit facilities unutilized	2,924	996	**3,920**	3,943

(1) The current portion was $735 million (December 31, 2017 - $312 million).

Credit facilities are syndicated primarily with large banks in Canada and the United States, with no one bank holding more than 20% of the total facilities. Approximately $5.0 billion of the total credit facilities are committed facilities with maturities ranging from 2019 through 2023.

Consolidated credit facilities of approximately $5.2 billion as at December 31, 2018 are itemized below.

Credit Facilities			
($ millions)		**Amount**	**Maturity**
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC *(1)*	US	900	October 2022
UNS Energy	US	500	October 2022
Central Hudson	US	250	*(2)*
FortisBC Energy		700	August 2023
FortisAlberta		250	August 2023
FortisBC Electric		150	April 2023
Other Electric		190	*(3)*
Other Electric	US	50	January 2020
Corporate and Other		1,350	*(4)*
Other facilities			
Central Hudson - uncommitted credit facility	US	40	n/a
FortisBC Electric - unsecured demand overdraft facility		10	n/a
Other Electric - unsecured demand facilities		25	n/a
Other Electric - unsecured demand facility and emergency standby loan	US	60	April 2019
Corporate and Other - unsecured non-revolving facility		35	n/a

(1) ITC also has a US$400 million commercial paper program, under which no amounts were outstanding as at December 31, 2018.
(2) US$50 million in July 2020 and US$200 million in October 2020
(3) $50 million in February 2019, $40 million in June 2021, and $100 million in August 2023
(4) $1.3 billion in July 2023, with the option to increase by an amount up to $500 million, and $50 million in April 2021

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $119 million as at December 31, 2018 (December 31, 2017 - $129 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 principal risks facing the Corporation. Other risks may arise or risks not currently considered material may become material in the future.

The Corporation's utilities are subject to substantial regulation and may be adversely affected by regulatory or legislative changes.

Regulated utility assets represented approximately 97% of total assets of Fortis as at December 31, 2018 (December 31, 2017 – 97%). 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; 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 results of operations, financial condition and cash flows of the Corporation's utilities. In addition, there is no assurance that the utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having a corresponding approved revenue requirement.

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

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

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

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

ITC's regulated operating subsidiaries provide transmission service under rates regulated by FERC. FERC has approved the cost-based formula rates used to calculate the annual revenue requirement, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of ITC's rates approved by FERC, including the formula rate templates, the rates of return on the actual equity portion of capital structure and the approved targeted capital structure, are subject to challenge by interested parties or by FERC. In addition, interested parties may challenge ITC's annual implementation and calculation of projected rates and formula rate true up pursuant to their

approved formula rates under their formula rate implementation protocols. End-use customers and entities supplying electricity to end-use customers may also attempt to influence government and/or regulators to change the rate-setting methodologies that apply to ITC, particularly if rates for delivered electricity increase substantially. If it is established that rates are unjust and unreasonable or that the terms of service provision are unduly discriminatory or preferential, then FERC can make appropriate prospective adjustments. This could result in lowered rates and/or refunds of amounts collected, any of which could have an adverse effect on ITC's results of operations, financial condition and cash flows.

For additional information on 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 financial effect on the Corporation.

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

The Corporation and its subsidiaries may also be exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and refinancing of long-term debt. At the utilities, interest expense is generally recovered in customer rates, as approved by the regulators. The inability to flow through interest costs to customers could have an adverse effect on the results of operations, financial condition and cash flows of the utilities. In addition, a change in the level of interest rates could affect the measurement and disclosure of the fair value of long-term debt.

Failure of facilities to operate as expected, from the occurrence of natural disasters or severe weather that may be caused by climate change, could have an adverse financial effect on the Corporation and its utilities.

The ongoing operation of the utilities' facilities involves risks customary to the electric and gas utility industry, including storms and severe weather conditions, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the utilities. Such occurrences could result in service disruptions and the inability to deliver electricity or gas to customers in an efficient manner, resulting in lower earnings and/or cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated cost recovery.

Despite preparations for severe weather, ice, wind and snowstorms, hurricanes and other natural disasters, weather will always remain a risk to the physical assets of utilities. Climate change may have the effect of increasing the severity and frequency of weather-related natural disasters that could affect the Corporation's operations and system reliability. 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.

The operation of the Corporation's electric and hydroelectric generating stations involves certain risks, including equipment breakdown or failure, that may result in the uncontrolled release of water, interruption of fuel supply and lower-than-expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of the generation business. There can be no assurance that the generation facilities of Fortis will continue to operate in accordance with expectations.

The operation of electricity transmission and distribution assets is also subject to certain risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. Certain of the Corporation's utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature. In addition, a significant portion of the utilities' infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged.

The Corporation's gas utilities are exposed to various operational risks associated with gas, including fires, explosions, pipeline leaks, accidental damage to mains and service lines, corrosion in pipes, pipeline or equipment failure, other issues that can lead to outages and/or leaks, and any other accidents involving gas that could result in significant operational disruptions and/or environmental liability. The operation and integrity of the gas assets are also at risk from natural disasters such as earthquakes, fires and floods, any of which have the potential to interrupt service, result in catastrophic loss and/or give rise to significant third-party liabilities.

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.

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 or 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 details on the Corporation's insurance coverage, refer to the insurance coverage risk discussion included in this section.

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 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, contractors and 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 reputations of the Corporation and the respective utility.

Changes in energy laws, regulations or policies could have an adverse financial effect on the Corporation and its utilities.

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

Failure by the Corporation's applicable utilities to comply with required reliability standards could have an adverse financial effect on the Corporation and its utilities.

As a result of the *Energy Policy Act* of 2005, owners, operators and users of the bulk electric system in the United States are subject to mandatory reliability standards developed by the North American Electric Reliability Corporation and its regional entities, which are approved and enforced by FERC. Many of these reliability standards have also been adopted, sometimes with modifications, in certain Canadian provinces including British Columbia, Alberta and Ontario. The standards prescribe benchmarks and measures that are designed to ensure that the bulk electric system operates reliably. Increased reliability standard compliance obligations may cause higher operating costs and/or capital expenditures for the Corporation's utilities. If any of the Corporation's utilities were found to be in violation of mandatory reliability standards,

they could also be subject to significant penalties. Both the costs of regulatory compliance and the costs that may be imposed due to actual or alleged compliance failures could have an adverse effect on the Corporation's results of operations, financial condition and cash flows.

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

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

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

The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial condition of the Corporation and its subsidiaries, the regulatory environment in which the Corporation's utilities operate and the outcome of regulatory decisions regarding capital structure and allowed ROEs, conditions in the capital and bank credit markets, ratings assigned by credit rating agencies, and general economic conditions. Funds generated from operations after payment of expected expenses, including interest payments, 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 2019 are expected to total $191 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 subsidiaries rated by credit rating agencies are subject to financial risk associated with changes in the credit ratings assigned to them. 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 subsidiaries.

In 2018 there were no changes to the debt credit ratings of the Corporation or its subsidiaries, with the exception of S&P's revised outlook for the Corporation from stable to negative in March 2018 due to a modest temporary weakening of financial measures resulting from U.S. tax reform, which reduced cash flow at the Corporation's U.S. regulated utilities. As a result of the Corporation's revised outlook, S&P also revised its outlook for ITC, TEP, FortisAlberta and Caribbean Utilities. Additionally, in July 2018 Moody's revised its outlook for Central Hudson from stable to negative due to the impacts of U.S. tax reform and higher capital expenditures. 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 have an adverse financial effect, and actual capital expenditures may be lower than planned.

The Corporation has a history of growth through acquisitions and 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 program generally consists of a large number of individually small projects; however, the Corporation and its utilities are also involved in a number of major capital projects. Risks related to such major capital projects include delays and cost overruns. Capital expenditures at the utilities are generally approved by the respective regulator; however, there is no assurance that any cost overruns would be approved for recovery in customer rates. Failure to realize the expected benefits of an acquisition and/or cost overruns on major capital projects could have an adverse effect on the Corporation's results of operations, financial condition and cash flows.

Additionally, the Corporation's five-year capital 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.

Changes in tax laws could have an adverse financial effect on the Corporation and its subsidiaries.

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

The timing or impacts of any future changes in tax laws, including the impacts of any subsequent technical corrections to existing tax laws, cannot be predicted. Additionally, certain aspects of U.S. tax reform are still subject to interpretation and clarification, including proposed regulations regarding base erosion and anti-abuse tax, and certain hybrid arrangements. Therefore, there may be further impacts on the results of operations, financial condition and cash flows of the Corporation and its U.S. utilities beyond those described herein.

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

As operators of critical energy infrastructure, the Corporation's utilities face a heightened risk of cyber-attacks. Despite risk-based cybersecurity programs that are continuously monitored for effectiveness, information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business, customer and employee information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation, transmission and distribution facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

In the event the Corporation's utilities' information or operations technology systems are breached, service disruptions, property damage, and 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 and financial markets, and expose it to claims for third-party damage. The financial impact of a material breach in cybersecurity, acts of war or terrorism could be material and may not be covered by insurance policies or, in the case of utilities, through regulatory cost recovery.

The Corporation's utilities are impacted by variability in weather due to seasonality and weather changes that affect water flows, which could have an adverse financial effect on the Corporation and its utilities.

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

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.

Earnings from non-regulated generation assets in Belize and British Columbia are sensitive to rainfall levels and the related impact on water flows. Hydrologic risk associated with hydroelectric generation at the Waneta Expansion and FortisBC Electric is reduced by the Canal Plant Agreement, under which fixed energy and capacity entitlements will be received based upon long-term average water flows. Prolonged adverse weather conditions, however, could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the entitlement of the Waneta Expansion and FortisBC Electric to capacity and energy under the Canal Plant Agreement.

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

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

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of energy supply cost will continue to exist in the future. Also, a severe and prolonged increase in such costs could have an adverse effect on 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 amount of energy supply cost 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, FortisTCI 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 are not expected to 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, 2018, the Corporation's corporately issued US$3,441 million (December 31, 2017 – US$3,385 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, 2018, the Corporation had approximately US$7,970 million (December 31, 2017 – US$7,548 million) in foreign net investments that were unhedged.

Consolidated earnings and cash flows of Fortis are impacted by fluctuations in the US dollar-to-Canadian dollar exchange rate. On an annual basis, it is estimated that a 5 cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.36 as at December 31, 2018 would increase or decrease earnings per common share of Fortis by approximately 6 cents, which reflects a hedging program implemented in 2017.

The Corporation entered into foreign exchange contracts to manage a portion of its exposure to foreign currency risk. There is no guarantee that such hedging strategies will be effective. In addition, currency hedging entails a risk of liquidity and, to the extent that the US dollar depreciates against the Canadian dollar, such hedges could result in losses greater than if hedging had not been used. Hedging arrangements could 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.

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

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

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

The competitiveness of gas relative to alternative energy sources could have an adverse financial effect on the Corporation.

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

Government policy has also impacted the competitiveness of gas in British Columbia. The Government of British Columbia has introduced changes to energy policy, including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels. The Government of British Columbia has yet to introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels.

The impact of these changes in energy policy may impact the competitiveness of gas relative to non-carbon-based or other energy sources.

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

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

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

Certain of the generating facilities from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have sole discretion or any ability to affect the management or operations of such facilities and, therefore, may not be able to ensure the proper management of the operations and maintenance of the generating facilities. Further, TEP may have no or limited ability to make determinations on how best to manage the changing economic conditions or environmental requirements that may affect such facilities. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact TEP's results of operations, financial condition and cash flows.

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

The emergence of initiatives designed to reduce greenhouse gas emissions and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce power, enable more efficient storage of energy or reduce power consumption. New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to have a significant impact on retail sales, which could negatively impact the 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 results of operations, financial condition and cash flows of the Corporation's utilities.

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

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

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

However, due to the significant current uncertainties related to federal and state regulation of greenhouse gas emissions in the United States, the ultimate financial and operational impact of such regulation cannot be determined at this time.

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

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

The Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their physical assets, for amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including practices of owners of similar assets and operations. However, a significant portion of the Corporation's regulated electric utilities' transmission and distribution assets are not covered under insurance, as is customary in North America, as the cost of coverage is not considered economically viable. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's utilities would likely apply to their respective regulatory authority to recover any loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs, loss of revenue and customer claims that are substantial in amount and could have an adverse effect on the Corporation's 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 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 licences, 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 material change to any required approval, the operation of the assets and the sale of electricity and gas could be prevented or become subject to additional costs, any of which could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation and its utilities.

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

External stakeholders are increasingly challenging investor-owned utilities in the areas of climate change, sustainability, diversity, utility ROEs and executive compensation. In addition, public opposition to larger infrastructure projects is becoming increasingly common, which can challenge a utility's ability to execute capital expenditure programs. While the Corporation is actively monitoring such 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 Indigenous Peoples, 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 Indigenous Peoples' lands and maintain gas facilities and electric generation, transmission and distribution facilities on lands that are subject to land claims by various Indigenous Peoples. A treaty negotiation process involving various Indigenous Peoples 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 Indigenous Peoples are participating in the process. To date, the policy of the Government of

British Columbia has been to structure settlements without prejudicing existing rights held by third parties. However, there can be no certainty that the settlement process will not have an adverse effect on the results of operations, financial condition and cash flows of the Corporation's utilities in British Columbia.

The Corporation has distribution assets on Indigenous Peoples' 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 Indigenous Peoples' band councils must grant approval. FortisAlberta may be unable to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have an adverse effect on FortisAlberta.

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

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

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

The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's utilities to attract, develop and retain skilled workforces. Like other utilities across Canada, the United States and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and a competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program will present challenges to ensuring 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 operation 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 is terminated for any reason, ITC may face difficulty finding a qualified replacement workforce 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 occurs 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, denial or revocation of permits or settlement of claims, could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation and its subsidiaries.

CHANGES IN ACCOUNTING POLICIES

Revenue Recognition
Effective January 1, 2018, Fortis adopted ASC 606, *Revenue from Contracts with Customers*, which clarifies the principles for recognizing revenue and requires additional disclosures. Fortis adopted this standard using the modified retrospective approach, under which comparative periods are not restated and the cumulative impact is recognized at the date of adoption, supplemented by additional disclosures. Upon adoption, there were no adjustments to the opening balance of retained earnings.

Most revenue is derived from energy sales and the provision of transmission services to customers based on regulator-approved tariff rates. Most contracts have a single performance obligation, being the delivery of energy or the provision of transmission services. No component of the transaction price is allocated to unsatisfied performance obligations. Revenue is generally measured in kilowatt hours, gigajoules or transmission load delivered. The billing of energy sales is based on customer meter readings, which occur systematically throughout each month. The billing of transmission services at ITC is based on peak monthly load.

FortisAlberta is a distribution company and is required by its regulator to arrange and pay for transmission services with the AESO. This includes the collection of transmission revenue from its customers, which occurs through the transmission component of its regulator-approved rates. FortisAlberta reports transmission revenue and expenses on a net basis.

Electricity, gas and transmission service revenue includes an estimate for unbilled energy consumed or service provided since the last meter reading that has not been billed at the end of the reporting period. Sales estimates generally reflect an analysis of historical consumption in relation to key inputs, such as current energy prices, population growth, economic activity, weather conditions and system losses. Unbilled revenue accruals are adjusted in the periods actual consumption becomes known.

Generation revenue from non-regulated operations is recognized on delivery at contracted fixed or market rates.

Variable consideration is estimated at the most likely amount and reassessed at each reporting date until the amount is known. Variable consideration, including amounts subject to a future regulatory decision, is recognized as a refund liability until entitlement is certain.

Revenue excludes sales and municipal taxes collected from customers. Prior to the adoption of ASC 606, Central Hudson recognized sales tax and FortisAlberta recognized municipal tax on a gross basis in both revenue and expense. The exclusion of these taxes from revenue resulted in a decrease in revenue of $49 million for 2018 compared to 2017.

The Corporation has elected not to assess or account for any significant financing components associated with revenue billed in accordance with equal payment plans as the period between the transfer of energy to customers and the customers' payment will be less than one year.

Revenue is disaggregated by geography, regulatory status, and substantially autonomous utility operations, as discussed in Note 5 of the 2018 Annual Financial Statements. This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer to allocate resources and evaluate performance.

Financial Instruments
Effective January 1, 2018, the Corporation adopted Accounting Standards Update ("ASU") No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*. Principally, it requires: (i) equity investments in unconsolidated entities not accounted for using the equity method to be measured at fair value through earnings; however, entities may 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 liabilities to be presented separately in the financial statement notes, grouped by measurement category and form. Adoption did not impact the consolidated financial statements.

Pension and Post-Retirement Benefit Costs
Effective January 1, 2018, the Corporation adopted ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost*, which requires current service costs to be grouped in the statement of earnings with other employee compensation costs arising from services rendered. The remaining components of net periodic benefit costs must be presented separately and outside of operating income. Additionally, only the service cost component can be capitalized. On adoption, the Corporation applied the presentation guidance retrospectively and the capitalization guidance prospectively. This resulted in a retrospective $11 million reclassification from Operating Expenses to Other Income, Net in the consolidated financial statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

Leases

ASU No. 2016-02, *Leases* ("ASC 842"), issued in February 2016, was effective for Fortis January 1, 2019 and is to be applied using a modified retrospective approach or an optional transition method with implementation options, referred to as practical expedients. Principally, it requires balance sheet recognition of a right-of-use asset and a lease liability by lessees for those leases that are classified as operating leases, along with additional disclosures.

Fortis has selected the optional transition method, which allows entities to continue to apply the current lease guidance in the comparative periods presented in the year of adoption and apply the transition provisions of the new guidance on the effective date of the new guidance. Fortis elected a package of practical expedients that allowed it to not reassess the lease classification of existing leases or whether existing contracts, including land easements, are or contain a lease. Finally, Fortis utilized the hindsight practical expedient to determine the lease term.

Upon adoption, Fortis will recognize right-of-use assets and corresponding lease liabilities of approximately$50 million for operating leases primarily related to office facilities and utility property. Operating leases related to vehicles and office equipment were identified and quantified as immaterial. Fortis has not identified an adjustment to opening retained earnings, and there will be no impact on earnings or cash flows.

Fortis implemented changes to processes and control activities related to monitoring the adoption of ASC 842 and made changes to accounting policies associated with accounting for lease assets and liabilities, and related income and expense, as of January 1, 2019.

Financial Instruments

ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, issued in June 2016, is effective for Fortis January 1, 2020 and is to be applied on a modified retrospective basis. Principally, it requires entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to estimate credit losses. The adoption of this ASU will not have a material impact on the consolidated financial statements and related disclosures.

Hedging

ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, issued in August 2017, was effective for Fortis January 1, 2019. Principally, it better aligns risk management activities and financial reporting for hedging relationships through changes to designation, measurement, presentation and disclosure guidance. For cash flow and net investment hedges that existed at the date of adoption, the amendments were applied as a cumulative-effect adjustment related to eliminating the separate measurement of ineffectiveness to accumulated other comprehensive income with a corresponding adjustment to opening retained earnings. Amended presentation and disclosure guidance was applied prospectively. The adoption of this ASU did not have a material impact on the consolidated financial statements and related disclosures.

Fair Value Measurement Disclosures

ASU No. 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement,* issued in August 2018, is effective for Fortis January 1, 2020 and is to be primarily applied on a retrospective basis, with certain disclosures requiring prospective application. Principally, it improves the effectiveness of financial statement note disclosures by clarifying what is required and important to users of the financial statements. In addition, the amendment removes (a) the amount of, and reasons for, transfers between level 2 and level 3 of the fair value hierarchy, (b) the policy for timing of transfers between levels, and (c) the valuation processes for level 3 fair value measurements. Fortis does not expect the adoption of this ASU to have a material impact on the related disclosures.

Pensions and Other Post-Retirement Plan Disclosures

ASU No. 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans*, issued in August 2018, is effective for Fortis January 1, 2021 and is to be applied on a retrospective basis for all periods presented. Principally, it modifies the disclosure requirements for employers with defined pension or other post-retirement plans and clarifies disclosure requirements. In addition, the amendments remove (a) the amounts in accumulated other comprehensive income expected to be recognized as components of net period benefit costs over the next fiscal period, (b) the amount and timing of plan assets expected to be returned to the employer, and (c) the effects of a one-percentage-point change on the assumed health care costs and the change in rates on service cost, interest cost and the benefit obligation for post-retirement health care benefits. Fortis does not expect the adoption of this ASU to have a material impact on the related disclosure.

FINANCIAL INSTRUMENTS

Excluding long-term debt, the consolidated carrying value of the Corporation's financial instruments approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

As at December 31, 2018, the carrying value of long-term debt, including the current portion, was$24,231 million (December 31, 2017 - $21,535 million) compared to an estimated fair value of $25,110 million (December 31, 2017 - $23,481 million).

The fair value of long-term debt is calculated using quoted market prices or, when unavailable, by either: (i) discounting the associated future cash flows 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 with similar maturities. Since the Corporation does not intend to settle the long-term debt prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The following table presents the fair value of the assets and liabilities that are accounted for at fair value on a recurring basis.

(in millions)	**Level 1** *(1)*	**Level 2** *(1)*	**Level 3** *(1)*	**Total**
As at December 31, 2018				
Assets				
Energy contracts subject to regulatory deferral *(2) (3)*	**$ — $**	**33 $**	**8 $**	**41**
Energy contracts not subject to regulatory deferral *(2)*	**—**	**13**	**3**	**16**
Other investments *(4)*	**155**	**—**	**—**	**155**
	$ 155 $	**46 $**	**11 $**	**212**
Liabilities				
Energy contracts subject to regulatory deferral *(3) (5)*	**$ — $**	**(86) $**	**(3) $**	**(89)**
Energy contracts not subject to regulatory deferral *(5)*	**—**	**(1)**	**—**	**(1)**
Foreign exchange contracts, interest rate and total return swaps *(6)*	**(8)**	**(1)**	**—**	**(9)**
	$ (8) $	**(88) $**	**(3) $**	**(99)**

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

(1) Under the hierarchy, fair value is determined using: (i) level 1 - unadjusted quoted prices in active markets; (ii) level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.
(2) Included in accounts receivable and other current assets or other assets
(3) 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.
(4) Included in other assets
(5) Included in accounts payable and other current liabilities or other liabilities
(6) Included in accounts receivable and other current assets, accounts payable and other current liabilities or other liabilities

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery.

The Corporation records all derivatives at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the derivatives as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

Energy contracts subject to regulatory deferral

UNS Energy holds electricity power purchase contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values were measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values were measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts and financial commodity swaps to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2018, unrealized losses of $57 million (December 31, 2017 - $87 million) were recognized as regulatory assets and unrealized gains of $9 million (December 31, 2017 - $2 million) were recognized in regulatory liabilities.

Energy contracts not subject to regulatory deferral

UNS Energy holds wholesale trading contracts that qualify as derivatives to fix power prices and realize potential margin, of which 10% of any realized gains are shared with customers through rate stabilization accounts. Fair values were measured using a market approach using independent third-party information, where possible.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in earnings. During 2018 unrealized losses of $12 million (2017 - unrealized gains of $36 million) were recognized in revenue.

Foreign exchange contracts

The Corporation holds US dollar foreign exchange contracts to mitigate exposure to volatility of foreign exchange rates. The contracts expire in 2019 and have a combined notional amount of $161 million. Fair value was measured using independent third-party information.

Unrealized gains and losses associated with changes in fair value are recognized in earnings. During 2018 unrealized losses of $11 million (2017 - unrealized gains of $3 million) were recognized in other income, net.

Interest rate and total return swaps

UNS Energy holds an interest rate swap to mitigate exposure to volatility in variable interest rates on capital lease obligations. The swap expires in 2020 and has a notional amount of $16 million. Fair value was measured using an income valuation approach based on six-month LIBOR.

Unrealized gains and losses associated with changes in the fair value of this interest rate swap, which was designated as a cash flow hedge, are recognized in other comprehensive income and reclassified to earnings through interest expense over the life of the hedged debt. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $3 million, net of tax.

The Corporation holds three total return swaps to manage the cash flow risk associated with forecasted future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $41 million and terms ranging from one to three years, expiring in January 2019, 2020 and 2021. Fair value was measured using an income valuation approach based on forward pricing curves.

Unrealized gains and losses associated with changes in the fair value of the total return swaps are recognized in earnings. During 2018 unrealized gains of less than $1 million (2017 - unrealized losses of less than $1 million) were recognized in other income, net.

Other investments

ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses on these funds are recognized in earnings. During 2018 unrealized gains of less than $1 million (2017 - unrealized gains of less than $1 million) were recognized in other income, net.

Volume of Derivative Activity

As at December 31, 2018, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

Volume	2018	2017
Energy contracts subject to regulatory deferral		
Electricity swap contracts *(GWh)*	**774**	1,291
Electricity power purchase contracts *(GWh)*	**651**	761
Gas swap contracts *(PJ)*	**203**	216
Gas supply contract premiums *(PJ)*	**266**	219
Energy contracts not subject to regulatory deferral		
Wholesale trading contracts *(GWh)*	**1,440**	2,387
Gas swap contracts *(PJ)*	**37**	36

CRITICAL ACCOUNTING ESTIMATES

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

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and liabilities arise as a result of the rate-setting process 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, 2018, Fortis recognized a total of $3.2 billion in regulatory assets (December 31, 2017 - $3.0 billion) and $3.6 billion in regulatory liabilities (December 31, 2017 - $3.4 billion). For further discussion of the nature of regulatory decisions, refer to the "Consolidated Financial Position" 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, 2018, the Corporation's consolidated property, plant and equipment and intangible assets were approximately $33.9 billion, or approximately 64% of total consolidated assets (December 31, 2017 - $30.7 billion, or approximately 64% of total consolidated assets). Depreciation and amortization was $1.2 billion for 2018 (2017 - $1.2 billion).

Depreciation rates of the Corporation's regulated utilities include a provision for estimated future asset removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability against which actual asset removal costs are netted when incurred. The estimate of asset removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2018 was $1.2 billion (December 31, 2017 - $1.1 billion).

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

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

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

Assessment for Impairment of Goodwill: Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets related to business acquisitions. Impairment testing is performed if an event or change in circumstances indicates that the fair value of a reporting unit may be below its carrying value. If that is determined to be the case, goodwill is written down to estimated fair value and an impairment loss is recognized.

Otherwise, Fortis performs an annual assessment for each of the 11 reporting units having goodwill. The primary method for estimating the fair value of 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 underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and 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 and compared to the results of the income approach.

As at December 31, 2018, consolidated goodwill totalled approximately $12.5 billion (December 31, 2017 - $11.6 billion). The increase in goodwill was due to the impact of foreign exchange associated with the translation of US dollar-denominated goodwill. No goodwill impairment was recognized in 2018 or 2017.

Income Tax Expense: Income tax expense is determined based on estimates of the Corporation's current income tax and estimates of deferred income tax resulting from temporary differences between the carrying values of assets and liabilities 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 tax expense, deferred income tax assets and liabilities, and any related valuation allowance, might vary from actual amounts incurred.

Employee Future Benefits: The following table summarizes the balance sheet impact of the defined benefit pension and OPEB plans as at December 31, 2018 and 2017, as well as the net benefit cost for the years then ended.

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2018**	2017	**2018**	2017
Benefit obligation	**(3,207)**	(3,215)	**(655)**	(665)
Plan assets	**2,830**	2,841	**293**	277
Funded status	**(377)**	(374)	**(362)**	(388)
Net benefit cost	**83**	87	**34**	32

Fortis and its subsidiaries each maintains one or a combination of defined benefit pension plans and OPEB plans for qualifying members. The main assumptions determined by management and used in the actuarial determination of the net benefit cost and related benefit obligation are the discount rate, the expected long-term rate of return on plan assets and, with respect to OPEBs, the health care cost trend rate.

Discount Rate
The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2018, and to determine net pension cost for 2019, is 4.07% compared to 3.58% assumed for the prior year. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments.

Consolidated defined benefit pension costs were comparable with 2017. Higher expected return on plan assets, lower interest and regulatory adjustments for 2018 compared to 2017 were largely offset by higher service costs and amortization of actuarial losses. Any increases or decreases in defined benefit net pension cost at the regulated utilities for 2019 are expected to be recovered from or refunded to customers in rates, subject to regulatory lag and forecast risk at certain of the utilities.

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 2019, is 5.80% compared to 5.97% used for 2018. The defined benefit pension plan assets experienced total negative returns of approximately $93 million in 2018 compared to expected positive returns of $162 million. The expected long-term rates of return on pension plan assets are developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

The OPEB plan assets at ITC, UNS Energy and Central Hudson experienced negative returns of $13 million in 2018 compared to expected positive returns of approximately $16 million.

The following table provides the sensitivities associated with a 100 basis point, or 1%, change in certain assumptions on the 2018 pension cost and related obligation.

Sensitivity Analysis Year Ended December 31, 2018 **(Decrease) increase**	Rate of Return - 1% change		Discount Rate - 1% change		Health Care Cost Trend Rate - 1% change	
($ millions)	**Increase**	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
Defined Benefit Pension Plans:						
Net pension benefit cost	**(26)**	**23**	**(39)**	**57**	**n/a**	**n/a**
Projected benefit obligation *(1)*	**15**	**(57)**	**(405)**	**509**	**n/a**	**n/a**
OPEB Plans:						
Net OPEB cost	**(3)**	**3**	**(8)**	**12**	**17**	**(11)**
Accumulated benefit obligation	**n/a**	**n/a**	**(88)**	**111**	**85**	**(67)**

(1) At FortisBC Energy and FortisBC Electric, certain defined benefit pension plans have pension indexing provisions that provide for a portion of investment returns to be allocated in order to provide for indexing of pension benefits. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation.

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

At FortisAlberta, as approved by the regulator, the cost of defined benefit pension plans is recovered in customer rates based on the cash payments made, with any difference between the cash payments made and the cost incurred being deferred as a regulatory asset or regulatory liability. ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net pension cost from the forecast net pension cost used to set customer rates. There can be no assurance, however, that the deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

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 approved rates. The development of 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, 2018, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $575 million (December 31, 2017 - $562 million) on consolidated revenue of $8.4 billion for 2018 (2017 - $8.3 billion).

Contingencies: In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline right of way on reserve lands. The pipeline was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in 2007. The Band seeks cancellation of the right of way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the Minister's consent and returned the matter to the Minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.

The Corporation and its subsidiaries are subject to various other 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.

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2018 or 2017.

Inter-company balances, transactions and 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. Inter-company transactions are summarized below.

Inter-Company Transactions		
Years ended December 31		
($ millions)	**2018**	2017
Sale of capacity from Waneta Expansion to FortisBC Electric	**47**	46
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**25**	24

As at December 31, 2018, accounts receivable included approximately $16 million due from BEL (December 31, 2017 - $20 million).

The Corporation periodically provides short-term financing to subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements. There were no material inter-segment loans outstanding as at December 31, 2018 and 2017.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31,2018, 2017 and 2016.

Selected Annual Financial Information			
Years ended December 31			
($ millions, except per share amounts)	**2018**	2017	2016
Revenue	**8,390**	8,301	6,838
Net earnings	**1,286**	1,125	713
Net earnings attributable to common equity shareholders	**1,100**	963	585
Basic earnings per common share	**2.59**	2.32	1.89
Diluted earnings per common share	**2.59**	2.31	1.89
Adjusted earnings per common share	**2.51**	2.47	2.33
Total assets	**53,051**	47,822	47,904
Long-term debt (excluding current portion)	**23,159**	20,691	20,817
Preference shares	**1,623**	1,623	1,623
Common shareholders' equity	**14,910**	13,380	12,974
Dividends declared per:			
Common share	**1.75**	1.65	1.55
First Preference Share, Series E *(1)*	**—**	—	0.6126
First Preference Share, Series F	**1.2250**	1.2250	1.2250
First Preference Share, Series G (2)	**1.0345**	0.9708	0.9708
First Preference Share, Series H	**0.6250**	0.6250	0.6250
First Preference Share, Series I	**0.7116**	0.5262	0.4874
First Preference Share, Series J	**1.1875**	1.1875	1.1875
First Preference Share, Series K	**1.0000**	1.0000	1.0000
First Preference Share, Series M	**1.0250**	1.0250	1.0250

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

(2) The annual dividend per share for the First Preference Shares, Series G was reset from $0.9708 to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.

2018/2017: For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders and basic earnings per common share, refer to the "Summary Financial Highlights" and "Consolidated Results of Operations" sections of this MD&A.

The growth in total assets was due to continued investment in energy infrastructure, driven by capital spending at the regulated utilities as well as favourable foreign exchange on the translation of US dollar-denominated assets. The increase in long-term debt was due to debt issuances at regulated utilities and foreign exchange, partially offset by scheduled debt repayments.

2017/2016: Revenue increased $1,463 million from 2016, driven by the acquisition of ITC in October 2016. Higher revenue at UNS Energy, mainly due to the impact of the rate case settlement effective February 2017 and the overall favourable impact of FERC-ordered transmission refunds, and the flow through in customer rates of overall higher energy supply costs were partially offset by unfavourable foreign exchange associated with the translation of US dollar-denominated revenue.

Net earnings attributable to common equity shareholders increased $378 million from2016, driven by a full year of earnings contribution at ITC, which was acquired in October 2016, lower Corporate and Other expenses, strong performance at UNS Energy, and higher earnings from Aitken Creek.

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

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

FOURTH QUARTER RESULTS

The following tables set forth financial information for the fourth quarters of 2018 and 2017.

Summary of Electricity and Energy Sales and Gas Volumes			
Fourth Quarters Ended December 31	**2018**	2017	Variance
Regulated Utilities			
UNS Energy - Electricity Sales *(GWh)*	**4,751**	3,553	1,198
UNS Energy - Gas Volumes *(PJ)*	**5**	4	1
Central Hudson - Electricity Sales *(GWh)*	**1,250**	1,195	55
Central Hudson - Gas Volumes *(PJ)*	**7**	6	1
FortisBC Energy *(PJ)*	**63**	69	(6)
FortisAlberta *(GWh)*	**4,343**	4,328	15
FortisBC Electric *(GWh)*	**839**	869	(30)
Other Electric *(GWh)*	**2,443**	2,376	67
Non-Regulated - Energy Infrastructure *(GWh)*	**85**	129	(44)

Electricity and Energy Sales
The increase in electricity sales was driven by higher electricity sales at UNS Energy, primarily resulting from an increase in short-term wholesale sales due to an increase in system capacity related to the lease of the Gila River generating station Unit 2.

Gas Volumes
Gas volumes were comparable with 2017, with a slight decrease that resulted from focused customer conservation efforts at FortisBC Energy in the fourth quarter of 2018.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders						
Fourth Quarters Ended December 31	Revenue			Net Earnings		
($ millions, except per share amounts)	**2018**	2017	Variance	**2018**	2017	Variance
Regulated Utilities						
ITC	**390**	396	(6)	**92**	(1)	93
UNS Energy	**541**	471	70	**27**	28	(1)
Central Hudson	**234**	211	23	**24**	22	2
FortisBC Energy	**371**	366	5	**72**	66	6
FortisAlberta	**140**	152	(12)	**22**	29	(7)
FortisBC Electric	**111**	107	4	**13**	13	—
Other Electric	**372**	347	25	**22**	25	(3)
Non-Regulated						
Energy Infrastructure	**50**	64	(14)	**22**	25	(3)
Corporate and Other	**—**	—	—	**(33)**	(73)	40
Inter-Segment Eliminations	**(3)**	(3)	—	**—**	—	—
Total	**2,206**	2,111	95	**261**	134	127
Basic Earnings per Common Share *($)*				**0.61**	0.32	0.29
Weighted Average Number of Common Shares Outstanding *(millions)*				**427.5**	420.1	7.4

Revenue
The increase in revenue was primarily due to higher electricity sales, driven by an increase in system capacity at UNS Energy, favourable foreign exchange, and the flow through in customer rates of higher overall commodity costs. The increase was partially offset by the recovery of lower federal corporate income tax in customer rates associated with U.S. tax reform.

Earnings
The increase in earnings was primarily due to lower income tax expense, primarily driven by the one-time expense of $146 million in 2017 associated with U.S. tax reform, along with the positive tax impact of the remeasurement of deferred tax liabilities associated with assets held for sale. The increase was partially offset by a $21 million unrealized foreign exchange gain on a US-dollar denominated affiliate loan in 2017.

Basic Earnings per Common Share
Basic earnings per common share were$0.29 higher compared to the fourth quarter of2017, due to higher earnings for the reasons noted above, partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment plan.

Summary of Consolidated Cash Flows			
Fourth Quarters Ended December 31			
($ millions)	**2018**	2017	Variance
Cash, Beginning of Period	**195**	252	(57)
Cash Provided by (Used in):			
Operating Activities	**537**	766	(229)
Investing Activities	**(999)**	(882)	(117)
Financing Activities	**598**	191	407
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**16**	—	16
Cash Associated with Assets Held for Sale	**(15)**	—	(15)
Cash, End of Period	**332**	327	5

The decrease in cash provided by operating activities for the quarter was primarily due to an unfavourable change in working capital driven by FortisAlberta due to the timing of transmission costs payments, lower cash earnings and unfavourable changes in long-term regulatory deferrals, driven by the deferral of higher gas storage and transportation costs at FortisBC Energy related to a gas pipeline incident in the fourth quarter of 2018.

The increase in cash used in investing activities for the quarter was due to higher capital spending, mainly at FortisBC Energy.

The increase in cash provided by financing activities for the quarter was primarily due to lower repayments of long-term debt and lower net repayments of credit facility borrowings and short-term borrowings. The increase was partially offset by a decrease in proceeds from the issuance of long-term debt, driven by ITC.

SUMMARY OF QUARTERLY RESULTS

Quarterly information has been obtained from the Corporation's Interim Financial Statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results		**Net Earnings Attributable to Common Equity Shareholders**	**Earnings per Common Share**	
	Revenue		**Basic**	**Diluted**
Quarter Ended	*($ millions)*	*($ millions)*	*($)*	*($)*
December 31, 2018	2,206	261	0.61	0.61
September 30, 2018	2,040	276	0.65	0.65
June 30, 2018	1,947	240	0.57	0.57
March 31, 2018	2,197	323	0.77	0.76
December 31, 2017	2,111	134	0.32	0.31
September 30, 2017	1,901	278	0.66	0.66
June 30, 2017	2,015	257	0.62	0.62
March 31, 2017	2,274	294	0.72	0.72

The summary of the past eight quarters reflects the Corporation's continued organic growth, seasonality associated with its businesses and the impact of U.S. tax reform, effective December 2017. Interim results will fluctuate due to the seasonal nature of electricity and gas demand, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel, purchased power and natural gas, which is flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric distribution utilities in the United States are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

December 2018/December 2017: Net earnings attributable to common equity shareholders were$261 million, or $0.61 per common share, for the fourth quarter of 2018 compared to earnings of$134 million, or $0.32 per common share, for the fourth quarter of 2017. 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 2018/September 2017: Net earnings attributable to common equity shareholders were$276 million, or $0.65 per common share, for the third quarter of 2018 compared to earnings of$278 million, or $0.66 per common share, for the third quarter of2017. The decrease in earnings was primarily due to: (i) the receipt of a break fee associated with the termination of the Waneta Dam purchase agreement recognized in the third quarter of 2017; and (ii) lower earnings from Aitken Creek related to unrealized net losses on the mark-to-market of natural gas derivatives quarter over quarter. The decrease was partially offset by: (i) rate base growth driven by ITC; (ii) favourable electricity sales at UNS Energy; (iii) performance at the Canadian and Caribbean utilities, tempered by higher operating and interest expenses at FortisBC Energy; and (iv) favourable foreign exchange.

June 2018/June 2017: Net earnings attributable to common equity shareholders were$240 million, or $0.57 per common share, for the second quarter of 2018 compared to earnings of$257 million, or $0.62 per common share, for the second quarter of 2017. The decrease in earnings was primarily due to: (i) lower earnings from Aitken Creek related to unrealized net losses on the mark-to-market of natural gas derivatives quarter over quarter; (ii) the impact of U.S. tax reform; (iii) unfavourable foreign exchange; and (iv) the favourable settlement of matters at UNS Energy pertaining to FERC-ordered transmission refunds in 2017. The decrease was partially offset by the settlement of FortisTCI's business interruption insurance claim related to the impact of Hurricane Irma, and growth in rate base.

March 2018/March 2017: Net earnings attributable to common equity shareholders were$323 million, or $0.77 per common share, for the first quarter of 2018 compared to earnings of$294 million, or $0.72 per common share, for the first quarter of 2017. The increase in earnings was primarily due to: (i) the one-time remeasurement of the Corporation's deferred income tax liabilities as a result of an election to file a consolidated state income tax return; (ii) the impact of a full quarter of new rates at UNS Energy compared to last year; and (iii) growth in rate base. The increase was partially offset by: (i) unfavourable foreign exchange; (ii) lower earnings from Aitken Creek related to unrealized net losses on the mark-to-market of natural gas derivatives quarter over quarter; (iii) timing differences at Newfoundland Power; and (iv) the favourable settlement of matters at UNS Energy pertaining to FERC-ordered transmission refunds of $7 million in 2017.

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

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws. As at December 31, 2018, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the President and Chief Executive Officer ("CEO") and the Executive Vice President, Chief Financial Officer ("CFO"), of the effectiveness of the Corporation's disclosure controls and procedures, as defined in the applicable Canadian and United States securities laws. Based on that evaluation, the CEO and CFO concluded that such disclosure controls and procedures are effective as at December 31, 2018.

Internal Control over Financial Reporting

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

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's internal control over financial reporting as at December 31, 2018, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as at December 31, 2018, the Corporation's internal control over financial reporting was effective.

During the year ended December 31, 2018, there have been no changes in the Corporation's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

OUTLOOK

Over the long term, Fortis is well positioned to enhance value for shareholders through the execution of its capital program, the balance and strength of its diversified portfolio of utility businesses, as well as growth opportunities within its service territories.

The Corporation's $17.3 billion five-year capital program is expected to increase rate base from $26.1 billion in 2018 to approximately $32.0 billion in 2021 and $35.5 billion in 2023, translating into three- and five-year compound annual growth rates of 7.1% and 6.3%, respectively. The five-year capital program addresses system capacity and improves safety and reliability for the benefit of customers through investments that improve and automate the electricity grid, address natural gas system capacity and gas line network integrity, increase cyber protection and allow the grid to deliver cleaner energy.

Fortis is focused on securing further growth opportunities at its subsidiaries, which include the ITC Lake Erie Connector Project, gas infrastructure opportunities at FortisBC Energy and renewable energy investments, including storage, at UNS Energy.

Fortis expects long-term sustainable growth in rate base to support continuing growth in earnings and dividends. Fortis is targeting average annual dividend growth of 6% through 2023. 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 program, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

OUTSTANDING SHARE DATA

As at February 14, 2019, the Corporation had issued and outstanding 428.6 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 14, 2019 is approximately 4.8 million.

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

Exhibit 99.4

Rule 13a-14(a) or Rule 15d-14(a) Certification - Chief Executive Officer

I, Barry V. Perry, certify that:

1. I have reviewed this annual report on Form 40-F of Fortis Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ Barry V. Perry
Barry V. Perry
President and Chief Executive Officer

St. John's, Canada
February 14, 2019

Exhibit 99.5

Rule 13a-14(a) or Rule 15d-14(a) Certification - Chief Financial Officer

I, Jocelyn H. Perry, certify that:

1. I have reviewed this annual report on Form 40-F of Fortis Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ Jocelyn H. Perry
Jocelyn H. Perry
Executive Vice President, Chief Financial Officer

St. John's, Canada
February 14, 2019

Exhibit 99.6

Rule 13a-14(b) Certification Chief Executive Officer

In connection with the annual report of Fortis Inc. (the "Company") on Form 40-F for the fiscal year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Barry V. Perry, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Barry V. Perry
Barry V. Perry
President and Chief Executive Officer

St. John's, Canada
February 14, 2019

Exhibit 99.7

Rule 13a-14(b) Certification Chief Financial Officer

In connection with the annual report of Fortis Inc. (the "Company") on Form 40-F for the fiscal year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jocelyn H. Perry, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Jocelyn H. Perry
Jocelyn H. Perry
Executive Vice President, Chief Financial Officer

St. John's, Canada
February 14, 2019

Exhibit 99.8

Consent of Report of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in Registration Statement Nos. 333-215777 and 333-226663 on Form S-8, 333-228593 on Form F-10, and 333-218032 on Form F-3 and to the use of our reports dated February 14, 2019 relating to the consolidated financial statements of Fortis Inc. and subsidiaries and the effectiveness of Fortis Inc.'s internal control over financial reporting appearing in this Annual Report on Form 40-F of Fortis Inc. for the year ended December 31, 2018.

/s/ Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 14, 2019