FORTIS INC.

Investing in Our Networks

Third Quarter 2018

FORTIS INC.

November 2, 2018

Fortis Inc. Reports Third Quarter 2018 Earnings

ST. JOHN'S, NEWFOUNDLAND AND LABRADOR - Fortis Inc. (TSX / NYSE:FTS)

Fortis Inc. ("Fortis" or the "Corporation") (TSX/NYSE:FTS), a leader in the North American regulated electric and gas utility industry, released its third quarter results today. The Corporation reported third quarter 2018 net earnings of $276 million, or $0.65 per common share.

"During the third quarter, all of our regulated utilities performed well and we made good progress towards completing our $3.2 billion capital plan for 2018," said Barry Perry, President and Chief Executive Officer, Fortis. "We recently announced a new plan that lifts our annual capital expenditures to approximately $3.5 billion per year over the next five years. Regulated investments in grid modernization, the delivery of cleaner energy and natural gas infrastructure are driving growth."

Reported Net Earnings

The Corporation reported third quarter net earnings attributable to common equity shareholders of $276 million, or $0.65 per common share, compared to $278 million, or $0.66 per common share, for the same period in 2017. On a year-to-date basis, net earnings attributable to common equity shareholders were $839 million, or $1.98 per common share, compared to $829 million, or $2.00 per common share, for the same period in 2017.

- Earnings per common share ("EPS") was comparable quarter over quarter. The third quarter of 2017 included the receipt of a $24 million break fee associated with the termination of the Waneta Dam acquisition.
- Strong performance at the U.S. utilities during the third quarter of 2018 was driven by capital investment at ITC as well as favourable electricity sales at UNS Energy associated with weather.
- The Canadian and Caribbean utilities also improved third quarter EPS, tempered by higher operating and interest expenses at FortisBC Energy in 2018.
- Other factors impacting the third quarter EPS included favourable foreign exchange offset by a higher weighted average number of common shares outstanding and a $5 million change in the unrealized net losses on mark-to-market of derivatives at the Aitken Creek natural gas storage facility quarter over quarter.

Adjusted Net Earnings[1]

Third quarter adjusted net earnings attributable to common equity shareholders were $276 million, or $0.65 per common share, compared to $254 million, or $0.61 per common share for the same period in 2017. This adjusts for the $24 million acquisition break fee received in the third quarter of 2017.

Year-to-date adjusted net earnings attributable to common equity shareholders were $809 million, or $1.91 per common share, compared to $794 million, or $1.92 per common share for the same period in 2017. This adjusts for a favourable one-time $30 million tax remeasurement in 2018, the $24 million acquisition break fee received in 2017, and an $11 million favourable settlement of matters pertaining to the Federal Energy Regulatory Commission ("FERC") ordered transmission refunds in 2017.

[1] **Non-US GAAP Measures**

Fortis uses financial measures that do not have a standardized meaning under generally accepted accounting principles in the United States of America ("US GAAP") and may not be comparable to similar measures presented by other entities. Fortis calculated the non-US GAAP measures by adjusting certain US GAAP measures for specific items that management believes are not reflective of normal, ongoing operations of the business. Refer to the Financial Highlights section of the Corporation's Management Discussion and Analysis for further discussion of these items.

Regulatory Proceedings
Fortis is focused on maintaining constructive regulatory relationships and outcomes across its North American utility group.

In August 2018 the Alberta Utilities Commission approved an allowed return on equity of 8.50% for FortisAlberta on a capital structure of 37% common equity for 2018 to 2020, unchanged from 2017.

On October 18, 2018, FERC issued an order in response to a third-party complaint challenging ITC's independence incentive adders that are included in transmission rates charged by ITC's Midcontinent Independent System Operator ("MISO") operating subsidiaries. The order reduced the adders to 0.25% effective April 20, 2018. On October 22, 2018, MISO filed a motion requesting an extension to January 17, 2019 to issue refunds.

Also, in October, FERC issued an order with respect to New England transmission owners' return on equity ("ROE") complaints. The order provides guidance on FERC's methodology for establishing ROEs, including addressing outstanding ROE complaints. Fortis views the new methodology to be generally constructive for transmission owners.

Execution of Growth Strategy and Outlook
Consolidated capital expenditures were $2.3 billion during the first nine months of 2018 and the Corporation remains on track to invest $3.2 billion in 2018. The five-year capital program for 2019 to 2023 is expected to be $17.3 billion, up $2.8 billion from the prior year's plan. Consolidated rate base is projected to increase from $26.1 billion in 2018 to approximately $32.0 billion in 2021 and $35.5 billion in 2023, translating into a three and five-year compound annual growth rate of 7.1% and 6.3%, respectively.

Beyond the base capital investment plan, Fortis continues to pursue additional organic growth as well as near and long-term development projects. Key development projects not yet included in the capital investment plan include a liquefied natural gas export terminal at the Tilbury facility in British Columbia; the fully permitted, cross-border, Lake Erie Connector electric transmission project in Ontario; and the Big Chino Valley Pumped Storage project in Arizona.

"Our focus on sustainable investments in our existing utilities is driving visible rate base growth over the next five years supporting our 6% average annual dividend growth target through 2023," said Mr. Perry.

"In October we published our 2018 Sustainability Report, detailing our commitment to the environment, our governance practices, our people and our involvement in the communities where we live and work. Fortis continues to strengthen its commitment to sustainability and deliver on customer expectations for reliable, safe, cleaner energy," concluded Mr. Perry.

About Fortis
Fortis is a leader in the North American regulated electric and gas utility industry with 2017 revenue of $8.3 billion and total assets of $50 billion as at September 30, 2018. The Corporation's 8,500 employees serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries.

Teleconference to Discuss Third Quarter 2018 Results

A teleconference and webcast will be held on November 2 at 8:30 a.m. (Eastern). Barry Perry, President and Chief Executive Officer, and Jocelyn Perry, Executive Vice President, Chief Financial Officer, will discuss the Corporation's third quarter 2018 results.

Analysts, members of the media and other interested parties in North America are invited to participate by calling 1.877.223.4471. International participants may participate by calling 647.788.4922. Please dial in 10 minutes prior to the start of the call. No pass code is required.

A live and archived audio webcast of the teleconference will be available on the Corporation's website, www.fortisinc.com.

A replay of the conference will be available two hours after the conclusion of the call until December 2, 2018. Please call 1.800.585.8367 or 416.621.4642 and enter pass code 4019827.

Forward-looking information

Fortis includes forward-looking information in this media release 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 included in this media release reflect expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: the Corporation's forecast consolidated and segmented capital spending for 2018 and the five-year period from 2019 through 2023; the Corporation's consolidated forecast rate base for 2021 and 2023; the nature, timing, benefits and expected costs of capital projects and additional opportunities beyond the base capital plan; and targeted average annual dividend growth through 2023.

Forward-looking information involves significant risk, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information. These factors or assumptions are subject to inherent risks and uncertainties surrounding future expectations generally, including those identified from time to time in the forward-looking information. Such risk factors or assumptions include, but are not limited to: reasonable decisions by utility regulators and the expectation of regulatory stability; the implementation of the Corporation's five-year capital expenditure plan; 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 realization of additional opportunities; the impact of fluctuations in foreign exchange; and the Board exercising its discretion to declare dividends, taking into account the business performance and financial condition of the Corporation. 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 continuous disclosure materials filed from time to time by the Corporation with Canadian securities regulatory authorities and the Securities and Exchange Commission. 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.

Additional Information

This media release should be read in conjunction with the Corporation's Management Discussion and Analysis and Consolidated Financial Statements. This and additional information can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

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Interim Management Discussion and Analysis

For the three and nine months ended September 30, 2018
Dated November 1, 2018

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FORWARD-LOOKING INFORMATION

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. The MD&A should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes thereto for the three and nine months ended September 30, 2018 ("Interim Financial Statements") and the MD&A and audited consolidated financial statements for the year ended December 31, 2017 included in the Corporation's 2017 Annual Report. Financial information contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, collectively referred to as "forward-looking information". Forward-looking information included in the MD&A reflect expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which include, without limitation: the expectation that regulatory deferral mechanisms will capture the financial impacts of changes in usage, gas costs and material costs incurred beyond the control of FortisBC Energy as a result of the incident affecting Enbridge Inc.'s natural gas transmission pipeline; the expectation that the Federal Energy Regulatory Commission's order reducing adders for the Midcontinent Independent System Operator regulated operating subsidiaries will not have a material adverse impact on the results of operations, cash flows or financial position; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the Corporation's forecast capital expenditures for 2018 and for the period from 2019 through 2023 and potential funding sources for the capital plan; the nature, timing, benefits, expected costs of certain capital projects including, without limitation, the Tilbury liquefied natural gas expansion, the Lower Mainland System Upgrade Project, the Wataynikaneyap Transmission Power Project, the Southline Transmission Project, the New Mexico Wind Project, and the Inland Gas Upgrades Project and additional opportunities beyond the base capital expenditure plan including the Lake Erie Connector Project and liquefied natural gas infrastructure investment opportunities in British Columbia; the expectation that subsidiary operating expenses and interest costs will be paid out of subsidiary operating cash flows; the expected sources of cash required of subsidiaries and Fortis to complete subsidiary capital expenditure programs; 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; expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout 2018; the intent of management to refinance certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities with long-term permanent financing; the expected timing and impact, if any, of the adoption of future accounting pronouncements; the expectation that long-term debt will not be settled prior to maturity; the Corporation's forecast rate base for 2021 and 2023; the expectation that the Corporation's significant capital expenditure plan will support continuing growth in earnings and dividends; and targeted average annual dividend growth through 2023.*

Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the realization of additional opportunities; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; no significant changes in tax laws; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel, coal and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans, environmental laws and regulations that may have a material negative affect on the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the continued tax deferred treatment of earnings from the Corporation's foreign operations; continued maintenance of information technology infrastructure and no material breach of cybersecurity; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital expenditure plan.

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

All forward-looking information in the MD&A is 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 2017 revenue of $8.3 billion and total assets of $50 billion as at September 30, 2018. The Corporation's 8,500 employees serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries.

Year-to-date September 30, 2018, the Corporation's electricity systems met a combined peak demand of 33,458 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,599 terajoules. For additional information on the Corporation's operations and reportable segments, refer to Note 1 to the Corporation's Interim Financial Statements and to the "Corporate Overview" section of the 2017 Annual MD&A.

FINANCIAL HIGHLIGHTS

Fortis has adopted a strategy of long-term profitable growth with the primary measures of financial performance being earnings per common share and total shareholder return. Key financial highlights are provided below.

Consolidated Financial Highlights						
Periods Ended September 30		**Quarter**			**Year-to-Date**	
($ millions, except for common share data)	**2018**	2017	Variance	**2018**	2017	Variance
Revenue	**2,040**	1,901	139	**6,184**	6,190	(6)
Energy Supply Costs	**574**	478	96	**1,810**	1,756	54
Operating Expenses	**557**	503	54	**1,663**	1,649	14
Depreciation and Amortization	**313**	290	23	**924**	885	39
Other Income, Net	**23**	22	1	**50**	70	(20)
Finance Charges	**245**	225	20	**724**	686	38
Income Tax Expense	**52**	106	(54)	**135**	314	(179)
Net Earnings	**322**	321	1	**978**	970	8
Net Earnings Attributable to:						
Non-Controlling Interests	**30**	27	3	**90**	92	(2)
Preference Equity Shareholders	**16**	16	—	**49**	49	—
Common Equity Shareholders	**276**	278	(2)	**839**	829	10
Net Earnings	**322**	321	1	**978**	970	8
Earnings per Common Share						
Basic *($)*	**0.65**	0.66	(0.01)	**1.98**	2.00	(0.02)
Diluted *($)*	**0.65**	0.66	(0.01)	**1.98**	2.00	(0.02)
Weighted Average Number of Common Shares Outstanding *(# millions)*	**425.6**	418.6	7.0	**423.8**	413.9	9.9
Cash Flow from Operating Activities	**796**	800	(4)	**2,067**	1,990	77

Revenue
The increase in revenue for the quarter was primarily due to favourable foreign exchange, rate base growth, increased electricity sales at UNS Energy, and the flow through in customer rates of higher overall purchased commodity costs. The increase was partially offset by lower customer rates reflecting the recovery of reduced income tax expense due to a change in the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018 ("U.S. tax reform").

The decrease in revenue year to date was primarily due to: (i) unfavourable foreign exchange; (ii) lower customer rates reflecting the recovery of reduced income tax expense due to U.S. tax reform; (iii) lower earnings from the Aitken Creek natural gas storage facility ("Aitken Creek") related to unrealized net losses of $28 million on the mark-to-market of natural gas derivatives period over period; and (iv) a change in presentation of certain revenues to a net basis upon implementation of Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customer*s. The decrease was partially offset by rate base growth, increased sales at UNS Energy and the flow through in customer rates of higher overall purchased commodity costs.

Energy Supply Costs
The increase in energy supply costs for the quarter and year to date was primarily due to increased electricity sales at UNS Energy due to an increase in system capacity and seasonality, and overall higher commodity costs. Unfavourable foreign exchange contributed to the increase for the quarter, while favourable foreign exchange partially offset the year-to-date increase.

Operating Expenses
The increase in operating expenses for the quarter was primarily due to the receipt of a break fee associated with the termination of the Waneta Dam purchase agreement recognized in the third quarter of 2017, along with unfavourable foreign exchange.

The increase in operating expenses year to date was due to the break fee discussed above and increased maintenance expense, mainly due to planned outages at UNS Energy, partially offset by the corresponding change in presentation discussed above for revenue, and favourable foreign exchange.

Depreciation and Amortization
The increase in depreciation and amortization for the quarter and year to date was primarily due to continued investment in energy infrastructure at the Corporation's utilities.

Other Income, Net
Other income, net of expenses, was comparable for the quarter.

The decrease in other income, net of expenses, year to date was due to the favourable settlement of matters at UNS Energy pertaining to the Federal Energy Regulatory Commission ("FERC") ordered transmission refunds in 2017, lower equity component of allowance for funds used during construction (“AFUDC”) at FortisBC Energy, and mark-to-market net losses on foreign exchange contracts and total return swaps in 2018.

Finance Charges
The increase in finance charges for the quarter and year to date was primarily due to overall higher debt levels at the Corporation's utilities to support capital expenditure programs.

Income Tax Expense
The decrease in income tax expense for the quarter and year to date was primarily due to U.S. tax reform. The decrease year to date was also due to a one-time $30 million remeasurement of the Corporation's deferred income tax liabilities that resulted from an election to file a consolidated state income tax return.

Net Earnings Attributable to Common Equity Shareholders and Basic Earnings per Common Share
The decrease in net earnings attributable to common equity shareholders for the quarter 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.

The increase in net earnings attributable to common equity shareholders year to date 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) rate base growth driven by ITC; and (iii) the impact of a full year of new rates compared to last year and favourable electricity sales at UNS Energy. The increase was partially offset by: (i) lower earnings from Aitken Creek related to unrealized net losses on the mark-to-market of natural gas derivatives; (ii) the receipt of a break fee, as discussed above; (iii) unfavourable foreign exchange; and (iv) the impact of U.S. tax reform.

Basic earnings per common share for the quarter and year to date were lower by $0.01 and $0.02, respectively, compared to the same periods in 2017. The decrease was due to the impact of the above-noted items on net earnings attributable to common equity shareholders and an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment and share plans, and on a year-to-date basis by the issuance of $500 million of common equity in March 2017.

Adjusted Net Earnings Attributable to Common Equity Shareholders and Adjusted Basic Earnings per Common Share
Fortis uses financial measures, being adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share, that do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. These adjusted results may not be comparable with similar adjusted results 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 believes are not reflective of the normal, ongoing operations of the business. 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						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions, except for common share data)	**2018**	2017	Variance	**2018**	2017	Variance
Net Earnings Attributable to Common Equity Shareholders	**276**	278	(2)	**839**	829	10
Adjusting Items:						
UNS Energy -						
Settlement of FERC-ordered transmission refunds	**—**	—	—	**—**	(11)	11
Corporate and Other -						
Remeasurement of deferred income tax liabilities - consolidated state income tax election	**—**	—	—	**(30)**	—	(30)
Acquisition break fee	**—**	(24)	24	**—**	(24)	24
Adjusted Net Earnings Attributable to Common Equity Shareholders	**276**	254	22	**809**	794	15
Adjusted Basic Earnings Per Common Share *($)*	**0.65**	0.61	0.04	**1.91**	1.92	(0.01)
Weighted Average Number of Common Shares Outstanding *(# millions)*	**425.6**	418.6	7.0	**423.8**	413.9	9.9

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2018**	2017	Variance	**2018**	2017	Variance
Regulated Utilities						
ITC	**97**	89	8	**269**	273	(4)
UNS Energy	**135**	112	23	**266**	242	24
Central Hudson	**17**	15	2	**50**	48	2
FortisBC Energy	**(22)**	(15)	(7)	**83**	88	(5)
FortisAlberta	**39**	35	4	**98**	91	7
FortisBC Electric	**12**	11	1	**43**	42	1
Other Electric	**30**	20	10	**83**	73	10
Non-Regulated						
Energy Infrastructure	**12**	21	(9)	**50**	69	(19)
Corporate and Other	**(44)**	(10)	(34)	**(103)**	(97)	(6)
Net Earnings Attributable to Common Equity Shareholders	**276**	278	(2)	**839**	829	10

A discussion of the financial results of the Corporation's reporting segments follows. A summary of any developments or changes in significant ongoing regulatory decisions and applications pertaining to the Corporation's utilities is provided in the "Regulatory Highlights" section of this MD&A.

REGULATED UTILITIES

ITC

Financial Highlights (1)						
Periods Ended September 30	Quarter			Year-to-Date		
($ millions)	**2018**	2017	Variance	**2018**	2017	Variance
Average US:CAD Exchange Rate (2)	**1.31**	1.25	0.06	**1.29**	1.31	(0.02)
Revenue	**386**	376	10	**1,114**	1,179	(65)
Earnings	**97**	89	8	**269**	273	(4)

(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 increase in revenue for the quarter was primarily due to rate base growth and approximately $16 million of favourable foreign exchange, partially offset by the recovery of lower federal corporate income tax in customer rates associated with U.S. tax reform.

The decrease in revenue year to date was primarily due to the impact of U.S. tax reform as discussed above and approximately $17 million of unfavourable foreign exchange, partially offset by rate base growth.

Earnings
The increase in earnings for the quarter was primarily due to approximately $4 million of favourable foreign exchange and rate base growth, partially offset by the net unfavourable impact of U.S. tax reform.

The decrease in earnings year to date was primarily due to the net unfavourable impact of U.S. tax reform, approximately $4 million of unfavourable foreign exchange, and higher business development costs, partially offset by rate base growth.

UNS ENERGY (1)

Financial Highlights	Quarter			Year-to-Date		
Periods Ended September 30	**2018**	2017	Variance	**2018**	2017	Variance
Average US:CAD Exchange Rate (2)	**1.31**	1.25	0.06	**1.29**	1.31	(0.02)
Electricity Sales *(gigawatt hours ("GWh"))*	**5,356**	4,416	940	**12,655**	11,418	1,237
Gas Volumes *(petajoules ("PJ"))*	**1**	1	—	**8**	9	(1)
Revenue *($ millions)*	**687**	599	88	**1,661**	1,609	52
Earnings *($ millions)*	**135**	112	23	**266**	242	24

(1) Includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. and UNS Gas, Inc.
(2) The reporting currency of UNS Energy is the US dollar.

Electricity Sales & Gas Volumes
The increase in electricity sales for the quarter and year to date was primarily a result of an increase in short-term wholesale sales due to an increase in system capacity related to Gila River generating station Unit 2 and warmer summer temperatures increasing air conditioning load. 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 the same periods in 2017.

Revenue
The increase in revenue for the quarter was primarily due to higher electricity sales as discussed above, approximately $27 million of favourable foreign exchange, and the flow through of higher energy supply costs. The increase was partially offset by the recovery of lower corporate income tax in customer rates associated with U.S. tax reform.

The increase in revenue year to date was primarily due to the same factors discussed above for the quarter, with the exception of foreign exchange which had an unfavourable impact of approximately $15 million. Also contributing to the increase in revenue year to date was the impact of the rate case settlement effective February 27, 2017, partially offset by the impact of U.S. tax reform.

Earnings
The increase in earnings for the quarter was primarily due to higher electricity sales as discussed above, lower income tax expense associated with U.S. tax reform, and approximately $5 million of favourable foreign exchange. The increase was partially offset by higher operating expenses resulting from planned generation outages in 2018.

The increase in earnings year to date was primarily due to the same factors discussed above for the quarter, with the exception of foreign exchange which had no significant impact year to date. Also contributing to the increase in earnings year to date was the impact of the rate case settlement effective February 27, 2017, partially offset by the favourable settlement of matters pertaining to FERC-ordered transmission refunds in 2017 and increased operating expenses resulting from planned generation outages in 2018.

CENTRAL HUDSON

Financial Highlights	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2018**	2017	Variance	**2018**	2017	Variance
Average US:CAD Exchange Rate [(1)]	**1.31**	1.25	0.06	**1.29**	1.31	(0.02)
Electricity Sales *(GWh)*	**1,416**	1,318	98	**3,868**	3,696	172
Gas Volumes *(PJ)*	**4**	3	1	**17**	16	1
Revenue *($ millions)*	**214**	197	17	**690**	661	29
Earnings *($ millions)*	**17**	15	2	**50**	48	2

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

Electricity Sales & Gas Volumes
The increase in electricity sales and gas volumes for the quarter and year to date 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 earnings.

Revenue
The increase in revenue for the quarter and year to date was primarily due to the recovery from customers of higher commodity costs 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 associated with U.S. tax reform. Revenue was also impacted by approximately $8 million of favourable and $12 million of unfavourable foreign exchange for the quarter and year to date, respectively.

Earnings
The increase in earnings for the quarter and year to date was primarily due to the rate increases effective July 1, 2017 and 2018 reflecting a return on increased rate base assets. Favourable foreign exchange of approximately $1 million also contributed to earnings for the quarter. The increase in earnings year to date was partially offset by storm restoration costs and approximately $1 million of unfavourable foreign exchange.

FORTISBC ENERGY

Financial Highlights	Quarter			Year-to-Date		
Periods Ended September 30	**2018**	2017	Variance	**2018**	2017	Variance
Gas Volumes *(PJ)*	**30**	27	3	**149**	152	(3)
Revenue *($ millions)*	**161**	156	5	**816**	832	(16)
Earnings *($ millions)*	**(22)**	(15)	(7)	**83**	88	(5)

Gas Volumes
The increase in gas volumes for the quarter was primarily due to higher average consumption, as a result of colder temperatures increasing heating load.

The decrease in gas volumes year to date was primarily due to lower average consumption as a result of warmer temperatures reducing heating load in the first half of 2018, partially offset by the increase in consumption in the third quarter of 2018, as discussed above.

Revenue
The increase in revenue for the quarter was primarily due to rate base growth, partially offset by lower commodity cost of natural gas charged to customers.

The decrease in revenue year to date was primarily due to lower commodity cost of natural gas charged to customers, partially offset by rate base growth.

Earnings
The decrease in earnings for the quarter and year to date was primarily due to the timing of operating expenses incurred throughout 2018 and higher interest expense, partially offset by rate base growth.

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 have a material impact on earnings.

On October 9, 2018, an incident took place affecting Enbridge Inc.'s natural gas transmission pipeline near Prince George, British Columbia ("BC"). This pipeline supplies natural gas which FortisBC Energy distributes to its customers in various locations across BC. Both the duration and amount of reduced capacity from the disrupted pipeline will determine the effect on FortisBC Energy and its customers. Regulatory deferral mechanisms are in place that are expected to capture the financial impact of changes in usage, gas costs and material costs incurred that are beyond the control of the Company. No FortisBC Energy infrastructure has been damaged as a result of this incident.

FORTISALBERTA

Financial Highlights	Quarter			Year-to-Date		
Periods Ended September 30	**2018**	2017	Variance	**2018**	2017	Variance
Energy Deliveries *(GWh)*	**4,240**	4,156	84	**12,811**	12,690	121
Revenue *($ millions)*	**155**	153	2	**439**	448	(9)
Earnings *($ millions)*	**39**	35	4	**98**	91	7

Energy Deliveries
The increase in energy deliveries for the quarter was primarily due to higher average consumption as a result of warmer temperatures increasing air conditioning load.

The increase in energy deliveries year to date was primarily due to increased average consumption as a result of colder temperatures increasing heating load in winter months and warmer temperatures increasing air conditioning load in summer months, along with higher farm and irrigation consumption due to lower precipitation, partially offset by a lower number of oil and gas customer sites period over period.

Revenue

The increase in revenue for the quarter was primarily due to 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 performance-based rate setting ("PBR") term through the return on equity ("ROE") efficiency carryover mechanism, and revenue associated with customer additions. Also increasing revenue for the quarter was a capital tracker revenue true-up of $5 million related to capital expenditures in 2016 and 2017. The increase was partially offset by a decrease of approximately $10 million resulting from an election to record municipal franchise fee revenue on a net basis upon implementation of ASC Topic 606, *Revenue from Contracts with Customers*, effective January 1, 2018, using the modified retrospective approach under which comparative periods are not restated.

The decrease in revenue year to date was primarily due to a decrease of approximately $32 million related to the change in presentation of municipal franchise fees as discussed above, partially offset by higher distribution rates, customer additions and capital tracker revenue also discussed above.

Earnings

The increase in earnings for the quarter and year to date was primarily due to higher distribution rates reflecting a return on increased rate base assets and the ROE efficiency carryover mechanism, the impact of customer additions, and capital tracker revenue as discussed above. The increase was partially offset by higher operating expenses related to vegetation management and labour costs, as well as increased interest expense related to a long-term debt issuance in 2017.

FORTISBC ELECTRIC

Financial Highlights	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2018**	2017	Variance	**2018**	2017	Variance
Electricity Sales *(GWh)*	**769**	779	(10)	**2,411**	2,436	(25)
Revenue *($ millions)*	**96**	93	3	**297**	291	6
Earnings *($ millions)*	**12**	11	1	**43**	42	1

Electricity Sales

The decrease in electricity sales for the quarter and year to date was due to lower average consumption as a result of colder temperatures reducing air conditioning load. Also contributing to the year-to-date decrease was reduced heating load in the first quarter of 2018 as a result of warmer temperatures.

Revenue

The increase in revenue for the quarter and year to date was primarily due to an increase in revenue recognized from third-party contract work.

Earnings

Earnings for the quarter and year to date were comparable with the same periods in 2017.

Variances from regulated forecasts used to set rates for electricity revenue and energy supply costs are flowed back to customers in future rates through approved regulatory deferral mechanisms and, therefore, do not have an impact on earnings.

OTHER ELECTRIC [1]

Financial Highlights	Quarter			Year-to-Date		
Periods Ended September 30	**2018**	2017	Variance	**2018**	2017	Variance
Average US:CAD Exchange Rate [2]	**1.31**	1.25	0.06	**1.29**	1.31	(0.02)
Electricity Sales *(GWh)*	**1,798**	1,740	58	**6,871**	6,841	30
Revenue *($ millions)*	**307**	283	24	**1,040**	1,016	24
Earnings *($ millions)*	**30**	20	10	**83**	73	10

(1) Comprised of utilities in Eastern Canada and the Caribbean as follows: Newfoundland Power Inc.; Maritime Electric Company, Limited; FortisOntario Inc.; a 49% equity investment in Wataynikaneyap Power Limited 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").

(2) 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 for the quarter was primarily due to higher electricity sales at FortisTCI, due to the unfavourable impact of Hurricane Irma on electricity sales during the third quarter of 2017, and customer additions.

The increase in electricity sales year to date was primarily due to higher electricity sales during the third quarter, as discussed above, as well as colder temperatures during the winter months increasing heating load. The increase was partially offset by the completion of a large project by a commercial customer in Newfoundland.

Revenue

The increase in revenue for the quarter and year to date was primarily due to the flow through in customer rates of higher fuel costs in the Caribbean and overall higher electricity sales. Favourable foreign exchange of approximately $3 million contributed to the increase for the quarter, while unfavourable foreign exchange decreased revenue by approximately $3 million on a year-to-date basis.

Earnings

The increase in earnings for the quarter was primarily due to changes in the seasonality of energy supply costs at Newfoundland Power, business development costs of approximately $2 million incurred in the third quarter of 2017 related to the Wataynikaneyap Transmission Power Project, and higher electricity sales, partially offset by lower equity income from BEL.

The increase in earnings year to date was primarily due to the receipt of FortisTCI's business interruption insurance proceeds in the second quarter of 2018, timing of operating expenses and higher electricity sales, partially offset by lower equity income from BEL.

NON-REGULATED

ENERGY INFRASTRUCTURE [1]

Financial Highlights	Quarter			Year-to-Date		
Periods Ended September 30	**2018**	2017	Variance	**2018**	2017	Variance
Energy Sales *(GWh)*	**151**	178	(27)	**768**	760	8
Revenue *($ millions)*	**37**	47	(10)	**134**	162	(28)
Earnings *($ millions)*	**12**	21	(9)	**50**	69	(19)

(1) Primarily comprised of long-term contracted generation assets in British Columbia and Belize, with a combined generating capacity of 391 MW, and the Aitken Creek natural gas storage facility in British Columbia, with a total working gas capacity of 77 billion cubic feet.

Energy Sales
The decrease in energy sales for the quarter was primarily due to lower rainfall reducing hydroelectric production in Belize. Energy sales increased year to date due to higher rainfall in the first half of 2018 increasing hydroelectric production in Belize.

Revenue and Earnings
The decrease in revenue and earnings for the quarter and year to date was primarily due to the unfavourable impact of the mark-to-market accounting of natural gas derivatives at Aitken Creek with unrealized losses of $2 million and $16 million, respectively, compared to unrealized gains of $3 million and $12 million, respectively, for the same periods in 2017. Revenue and earnings for the quarter were also impacted by lower hydroelectric production in Belize. The decrease in revenue and earnings year to date was partially offset by increased gas volumes and favourable pricing at Aitken Creek during the first half of 2018.

CORPORATE AND OTHER [(1)]

Financial Highlights						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2018**	2017	Variance	**2018**	2017	Variance
Net loss	**(44)**	(10)	(34)	**(103)**	(97)	(6)

[(1)] Includes Fortis net Corporate expenses and non-regulated holding company expenses

The increase in net expenses for the quarter and year to date was primarily driven by the receipt of a $24 million break fee associated with the termination of the Waneta Dam purchase agreement in the third quarter of 2017. Net expenses were also impacted by U.S. tax reform, which resulted in lower income tax recovery due to holding company interest being deductible at a lower corporate tax rate of 21%. The increase in net expenses year to date was partially offset by: (i) higher income tax recovery, due to a one-time $30 million remeasurement of the Corporation's deferred income tax liabilities which resulted from an election to file a consolidated state income tax return; and (ii) lower stock-based compensation and finance charges, which were substantially offset by mark-to-market net losses on foreign exchange contracts and total return swaps.

REGULATORY HIGHLIGHTS

Regulation of the Corporation's utilities is generally consistent with that disclosed in its 2017 Annual MD&A. A summary of significant regulatory developments year-to-date 2018 follows.

U.S. Tax Reform
The Corporation's U.S. utilities are working with their respective regulators to return to customers the net income tax savings resulting from U.S. tax reform.

ITC: In April 2018 ITC reposted formula rates charged to customers of its Midcontinent Independent System Operator ("MISO") regulated operating subsidiaries retroactive to January 1, 2018, as approved by FERC. As at September 30, 2018, the amounts owing had been substantially 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 September 30, 2018, a regulatory liability of $3 million (US$2 million) was recognized for amounts to be returned to customers during the remainder of 2018. 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. The proposal is currently being reviewed by FERC.

Central Hudson: In June 2018, as part of its approval of a joint proposal, discussed below, the New York Public Service Commission ("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 September 30, 2018, a regulatory liability of $12 million (US$10 million) was recognized related to the income tax savings realized in the first six months of 2018. As approved by the PSC, the refund of this regulatory liability to customers will be determined as part of a future regulatory proceeding.

ITC

Independence Incentive Adders

In April 2018 a third-party complaint was filed with FERC challenging independence incentive adders that were included in transmission rates charged by ITC's MISO-regulated operating subsidiaries. Independence incentive adders were established to encourage transmission investment and recognize that ITC's operating subsidiaries are independent, dedicated transmission-only operations, with no affiliation to market participants in their regions. The adders allowed up to 0.50% or 1.00% to be added to the authorized ROE, subject to any ROE cap established by FERC. On October 18, 2018, FERC issued an order in respect of this matter reducing the adders for each of the MISO-regulated operating subsidiaries to 0.25% effective April 20, 2018. On October 22, 2018, MISO filed a motion requesting an extension to January 17, 2019 to issue refunds. The resolution of this proceeding is not expected to have a material adverse impact on results of operations, cash flows or financial position.

ROE Complaints

On October 16, 2018, in response to complaints challenging the methodology used by FERC in setting the regional base ROE for ISO New England transmission owners, FERC issued an order proposing a new methodology for determining (i) when an existing ROE is no longer just and reasonable, and (ii) the regional base ROE if an existing ROE is found to no longer be just and reasonable. If finalized, this proposed methodology will be used to address ROE complaints currently pending before FERC, including ITC's outstanding ROE complaints.

Central Hudson

In June 2018 the 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 Proceeding: Oral hearings to determine the ROE and capital structure for 2018, 2019 and 2020 were completed in March 2018. In August 2018 the Alberta Utilities Commission ("AUC"), approved an allowed ROE of 8.50% on a capital structure of 37% common equity for 2018, 2019 and 2020, unchanged from 2017.

Next Generation Performance-Based Rate Setting Proceeding: In March 2018 the AUC approved the Company's 2018 distribution rates, on an interim basis, until true-up amounts are finalized. New rates were effective January 1, 2018 with collection from customers effective April 1, 2018. Key provisions included an increase of approximately 5.5% in the distribution component of rates.

FortisAlberta is pursuing options to appeal certain elements of the rate-setting design for the second PBR term.

CONSOLIDATED FINANCIAL POSITION

Significant Changes in the Consolidated Balance Sheets between September 30, 2018 and December 31, 2017

Balance Sheet Account	**Increase / (Decrease)** [1] *($ millions)*	**Explanation**
Cash and cash equivalents	(132)	The decrease was mainly due to the timing of transmission cost payments at FortisAlberta and a debt issuance at ITC in November 2017.
Property, plant and equipment, net	2,059	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, partially offset by depreciation.
Goodwill	295	The increase was due to foreign exchange.
Accounts payable and other current liabilities	(147)	The decrease was primarily due to the timing of the declaration of common share dividends and lower amounts owing for energy supply costs associated with the seasonality of operations. The decrease was partially offset by capital accruals mainly at UNS Energy and foreign exchange.
Regulatory liabilities (including current and long-term)	155	The increase was mainly due to the normal operation of rate stabilization accounts at ITC and foreign exchange.
Deferred income tax liabilities	235	The increase was mainly due to timing differences related to capital expenditures at the regulated utilities and foreign exchange.
Long-term debt (including current portion and short-term borrowings)	897	The increase was mainly due to the issuance of first mortgage bonds by ITC and debt issuances at other regulated utilities. The increase was also due to foreign exchange and higher net borrowings under committed credit facilities, partially offset by regularly scheduled debt repayments.
Capital lease and finance obligations (including current portion)	202	The increase was mainly due to UNS Energy's recognition of a capital lease for Gila River generating station Unit 2.
Shareholders' equity	981	The increase was due to: (i) net earnings attributable to common shareholders for the nine months ended September 30, 2018, less dividends declared on common shares; (ii) the 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; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans.

(1) Includes the impact of foreign exchange based upon the closing foreign exchange rate at September 30, 2018 of US$1.00=CAD$1.29 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 is provided below, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows Periods Ended September 30 *($ millions)*	**Quarter** **2018**	 2017	 Variance	**Year-to-Date** **2018**	 2017	 Variance
Cash, Beginning of Period	**197**	231	(34)	**327**	269	58
Cash Provided by (Used in):						
Operating Activities	**796**	800	(4)	**2,067**	1,990	77
Investing Activities	**(783)**	(683)	(100)	**(2,253)**	(2,143)	(110)
Financing Activities	**(12)**	(87)	75	**46**	148	(102)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(3)**	(9)	6	**8**	(12)	20
Cash, End of Period	**195**	252	(57)	**195**	252	(57)

Operating Activities
Cash provided by operating activities was comparable for the quarter.

The increase in cash provided by operating activities year to date was primarily due to favourable changes in working capital, mainly due to the payment of an ROE complaint refund in the first quarter of 2017 at ITC, and higher cash earnings, mainly due to warmer temperatures increasing energy consumption at UNS Energy in 2018, partially offset by lower receipts from operating revenue at U.S. subsidiaries as a result of U.S. tax reform.

Investing Activities
The increase in cash used in investing activities for the quarter and year to date was due to higher capital spending, primarily at UNS Energy.

Financing Activities
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, partially offset by lower proceeds from the issuance of long-term debt.

The decrease in cash provided by financing activities year to date was primarily due to lower proceeds from the issuance of long-term debt and higher repayments of long-term debt, partially offset by higher credit facility borrowings at the regulated utilities.

In the first quarter of 2017, approximately 12.2 million common shares of Fortis were issued to an institutional investor for proceeds of $500 million. The proceeds were used to repay 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						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2018**	2017	Variance	**2018**	2017	Variance
ITC [(1)]	**(3)**	—	(3)	**287**	601	(314)
Central Hudson [(2)]	**—**	75	(75)	**32**	75	(43)
FortisAlberta [(3)]	**149**	199	(50)	**149**	199	(50)
Newfoundland Power	**—**	—	—	**—**	75	(75)
FortisOntario [(4)]	**100**	—	100	**100**	—	100
Caribbean Utilities	**—**	—	—	**—**	80	(80)
FortisTCI [(5)]	**7**	—	7	**37**	—	37
Total	**253**	274	(21)	**605**	1,030	(425)

(1) In March 2018 ITC issued 35-year US$225 million first mortgage bonds at 4.00%. The net proceeds were used to repay maturing long-term debt, repay credit facility borrowings, finance capital expenditures and for general corporate purposes.

(2) In June 2018 Central Hudson issued 30-year US$25 million unsecured notes at 4.27%. The net proceeds were used for general corporate purposes.

(3) In September 2018 FortisAlberta issued 30-year $150 million unsecured debentures at 3.73%. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

(4) In August 2018 FortisOntario issued 30-year $100 million unsecured notes at 4.10%. The net proceeds were used to repay maturing long-term debt and for general corporate purposes.

(5) In February 2018 FortisTCI issued 5-year US$25 million unsecured notes at a floating interest rate of a one-month LIBOR plus a spread of 1.75%. In September 2018 FortisTCI entered into a 7-year US$10 million unsecured non-revolving term loan credit agreement with a floating interest rate of a one-month LIBOR plus a spread of 1.75%. As at September 30, 2018, borrowings under the term loan credit agreement were US$5 million. The net proceeds were used to repay a hurricane-related emergency standby loan 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 the third quarter of 2018 totalled $110 million, net of $71 million of dividends reinvested, compared to $106 million, net of $61 million of dividends reinvested, paid in the third quarter of 2017. Common share dividends paid year-to-date 2018 were $340 million, net of $200 million of dividends reinvested, compared to $308 million, net of $186 million of dividends reinvested, paid year-to-date 2017. The dividend paid per common share for each of the first, second and third quarters of 2018 was $0.425 compared to $0.40 for the same periods in 2017. The weighted average number of common shares outstanding for the third quarter and year-to-date of 2018 was 425.6 million and 423.8 million, respectively, compared to 418.6 million and 413.9 million for the same periods in 2017.

On October 15, 2018, Fortis declared a dividend of $0.45 per common share payable on December 1, 2018.

On October 29, 2018, Central Hudson issued 8-year US$40 million unsecured notes at 3.99% and 15-year US$40 million unsecured notes at 4.21%. The net proceeds will be used to repay maturing long-term debt and for general corporate purposes.

On November 1, 2018, ITC issued 33-year US$162 million first mortgage bonds at 4.32% and expects to issue an additional US$13 million in early November. The net proceeds will be used to repay credit facility borrowings, finance capital expenditures and for general corporate purposes.

CONTRACTUAL OBLIGATIONS

There were no material changes in contractual obligations from that disclosed in the Corporation's 2017 Annual MD&A, except issuances of long-term debt stated above and other items as follows.

In March 2018 Maritime Electric extended its power purchase agreement with New Brunswick Power from March 2019 to February 2024, increasing the total commitment under this agreement by approximately $262 million as at September 30, 2018.

In May 2018, following the acquisition of Gila River generating station Units 1 and 2 by a third party with whom UNS Energy has a power purchase agreement, UNS Energy recorded an increase of US$164 million to capital lease obligations to reflect the anticipated exercising of UNS Energy's option to purchase Unit 2 in December 2019.

CAPITAL STRUCTURE

The Corporation's principal business of regulated electric and gas utilities requires ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure that will enable it to maintain investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in their customer rates.

The consolidated capital structure of Fortis is presented below.

Capital Structure	**As at**			
	September 30, 2018		December 31, 2017	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [1]	**22,970**	**59.0**	21,739	59.2
Preference shares	**1,623**	**4.2**	1,623	4.4
Common shareholders' equity	**14,361**	**36.8**	13,380	36.4
Total	**38,954**	**100.0**	36,742	100.0

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

Including amounts related to non-controlling interests, the Corporation's capital structure as at September 30, 2018 was 56.3% total debt and capital lease and finance obligations (net of cash), 4.0% preference shares, 35.2% common shareholders' equity and 4.5% non-controlling interests (December 31, 2017 - 56.5% total debt and capital lease and finance obligations (net of cash), 4.2% preference shares, 34.8% common shareholders' equity and 4.5% non-controlling interests).

CREDIT RATINGS

As at September 30, 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 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 ITC, TEP, FortisAlberta and Caribbean Utilities.

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.

CAPITAL EXPENDITURE PLAN

A breakdown of the consolidated capital expenditures by reporting segment is provided below.

Consolidated Capital Expenditures [1]
Year-to-date September 30, 2018
($ millions)

	Regulated									
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	Total Regulated Utilities	Non-Regulated [2]	Total
Total	717	419	175	318	325	81	193	**2,228**	**37**	**2,265**

[1] Represents cash payments to construct property, plant and equipment and intangible assets, as reflected on the condensed consolidated interim statement of cash flows. Excludes the non-cash equity component of allowance for funds used during construction.
[2] Includes Energy Infrastructure and Corporate and Other segments.

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 for 2018 are forecast to be approximately $3.2 billion. The Corporation continues to advance its significant capital projects and there have been no material changes in the overall expected level, nature and timing of the Corporation's significant capital projects from those that were disclosed in the 2017 Annual MD&A with the exception of those noted below for FortisBC Energy.

Approximately $460 million, including AFUDC and development costs, has been invested in the Tilbury LNG facility expansion, in British Columbia, to the end of the third quarter of 2018. The total cost of the project is estimated at approximately $470 million, including approximately $70 million of AFUDC and development costs, and includes a new LNG storage tank and liquefier. The commissioning process of the facility was interrupted in the third quarter of 2017. The restart of commissioning has begun with LNG production anticipated in the fourth quarter of 2018. Subject to the commissioning and LNG production going as planned, the project will be completed in 2019.

FortisBC Energy's Lower Mainland System Upgrade project is designed to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area 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 Lower Mainland Intermediate Pressure System Upgrade ("LMIPSU") phase, which is focused on addressing pipeline condition issues. Construction activities for the CTS phase are complete, and the new pipelines have been commissioned and are in-service. FortisBC Energy conducted further detailed engineering work and evaluated construction bids and other costs which resulted in a revised cost estimate for the LMIPSU. The LMIPSU is expected to be constructed primarily during 2018 and 2019. The total capital cost of both phases of the Lower Mainland System Upgrade is now estimated to be approximately $640 million.

Five-Year Capital Program

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 the $14.5 billion disclosed in the 2017 Annual MD&A for the period from 2018 through 2022. The improvement in the five-year capital program is the result of the Corporation’s sustainable organic growth platform, the inclusion of Fortis’ effective investment in the Wataynikaneyap Transmission Power Project, and reflects 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 utility businesses and contains only a small number of major projects.

The Wataynikaneyap Transmission Power Project will connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid through 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 22 First Nations communities (51%), in partnership with Fortis (49%). In 2016 the Government of Ontario designated Wataynikaneyap Power as the licensed transmission company to complete this project. In 2017 the OEB approved a deferral account to recover development costs incurred between November 2010 and the commencement of construction. 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 is fully funded by the Canadian government and is expected to be completed by the end of 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 early 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.

At ITC, the five-year capital program has increased by approximately $900 million. The increase is driven by infrastructure investments for reliability improvements, increased capacity needs and new interconnections in support of economic development and changes in generation sources.

The five-year capital program includes two new major capital projects at UNS Energy. The Southline Transmission Project is a 600MW transmission line designed to collect and transmit electricity across southern New Mexico and southern Arizona. UNS Energy expects to purchase a 250MW ownership in the project. Construction is expected to commence in 2019, with completion expected in 2021. The capital cost of the Southline Transmission 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 a New Mexico Wind Project.

The New Mexico Wind Project is a 750MW 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 150MW ownership under a build-transfer asset contract, with an option to purchase additional ownership in the future. Construction is expected to commence in 2018, with completion expected in 2020. The capital cost of the project for UNS Energy is estimated at approximately $280 million (US$217 million).

The five-year capital program also includes $220 million associated with a multi-year Inland Gas Upgrades Project at FortisBC Energy. The project will provide gas line modifications and replacements enabling in-line inspection capabilities, a key tool to confirm the integrity of transmission gas lines. A Certificate of Public Convenience and Necessity (“CPCN”) application is expected to be filed with the British Columbia Utilities Commission in the fourth quarter of 2018 and approval is expected in the second half of 2019. Subject to the CPCN approval, construction of the project is expected to commence in 2020.

Also included in the five-year capital program is approximately $570 million associated with a multi-year Transmission Integrity Management Capabilities Project at FortisBC Energy, an increase of approximately $260 million from the amount disclosed in the 2017 Annual MD&A. The project is focused on improving gas line safety and the integrity of the high-pressure transmission system, including gas line modifications and looping.

The five-year capital program is expected to be funded with cash from operations, debt raised at the utilities and common equity from the Corporation's dividend reinvestment plan. The remaining funds required to finance the increased growth in regulated assets are expected to be generated from asset sales, with approximately $1 billion to $2 billion of proceeds expected over the five-year planning period. The Corporation's at-the-market common equity program will also be available to provide further financing flexibility.

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 base 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 - 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 have 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 subsidiary operating cash flows, with varying levels of residual cash flows available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from Fortis.

Cash required of Fortis to support subsidiary capital expenditure programs is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt as well as proceeds from the dividend reinvestment plan and at-the-market common equity program. 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 of and the related cash payments from subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis. These include restrictions by certain regulators limiting the amount of annual dividends and restrictions by certain lenders limiting the amount of debt to total capitalization at the subsidiaries. In addition, there are practical limitations on using the net assets of each of the Corporation's regulated subsidiaries to pay dividends based on management's intent to maintain the subsidiaries' regulator-approved capital structures. 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 November 2016 Fortis filed a short-form base shelf prospectus, under which the Corporation may issue common or preference shares, subscription receipts or debt securities in an aggregate principal amount of up to $5 billion during the 25-month life of the base shelf prospectus. In March 2018 the Corporation established an at-the-market common equity program that allows the Corporation to issue up to $500 million of common shares from treasury to the public at the Corporation's discretion, effective until December 2018. In July 2017 Fortis exchanged its US$2.0 billion ($2.6 billion) unregistered senior unsecured notes for US$2.0 billion ($2.6 billion) registered senior unsecured notes under the base shelf prospectus. In March 2017 Fortis issued $500 million common equity and in December 2016 issued $500 million unsecured notes at 2.85%, both under the base shelf prospectus. A principal amount of approximately $1.0 billion remains under the base shelf prospectus.

As at September 30, 2018, management expects consolidated fixed-term debt maturities and repayments to average approximately $759 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.

Fortis and its subsidiaries were in compliance with debt covenants as at September 30, 2018 and are expected to remain compliant throughout 2018.

CREDIT FACILITIES

As at September 30, 2018, the Corporation and its subsidiaries had consolidated credit facilities of approximately $5.0 billion, of which approximately $3.9 billion was unused, including $1.1 billion unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with large banks in Canada and the United States, with no one bank holding more than 20% of these facilities. Approximately $4.8 billion of the total credit facilities are committed facilities with maturities ranging from 2019 through 2023.

Credit facilities are summarized below.

Credit Facilities			**As at**	
($ millions)	Regulated Utilities	Corporate and Other	**September 30, 2018**	December 31, 2017
Total credit facilities	3,648	1,385	**5,033**	4,952
Credit facilities utilized:				
Short-term borrowings	(37)	(2)	**(39)**	(209)
Long-term debt (including current portion) [(1)]	(762)	(236)	**(998)**	(671)
Letters of credit outstanding	(69)	(55)	**(124)**	(129)
Credit facilities unutilized	2,780	1,092	**3,872**	3,943

(1) The current portion was $552 million (December 31, 2017 - $312 million).

Borrowings under long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods. There were no material changes in credit facilities from that disclosed in the Corporation's 2017 Annual MD&A.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $124 million as at September 30, 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

Business risks of the Corporation were generally consistent with those disclosed in the Corporation's 2017 Annual MD&A. Updates to regulatory risk and credit ratings are provided in the "Regulatory Highlights" and "Credit Ratings" sections of this MD&A.

CHANGES IN ACCOUNTING POLICIES

The Interim Financial Statements have been prepared following the same accounting policies and methods as those used to prepare the Corporation's 2017 annual audited consolidated financial statements, except as described below.

Revenue

Effective January 1, 2018, Fortis adopted ASC Topic 606, *Revenue from Contracts with Customers*, which clarifies the principles for recognizing revenue and requires additional disclosures. Fortis adopted the new 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 of the Corporation's 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. 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 Alberta Electric System Operator. These services include the collection of transmission revenue from its customers, which is achieved through invoicing the customers' retailers through the transmission component of its regulator-approved rates. FortisAlberta reports revenue and expenses related to transmission services on a net basis.

Electricity, gas and transmission service revenue includes an unbilled revenue estimate for energy consumed or services provided since the last meter reading that have not been billed at the end of the accounting 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 rates.

The Corporation estimates variable consideration at the most likely amount and reassesses its estimate 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 the Corporation is certain that it will be entitled to the consideration.

The Corporation's revenue excludes sales and municipal taxes collected from customers. Prior to the adoption of ASC Topic 606, Central Hudson recognized sales tax and FortisAlberta recognized municipal tax on a gross basis, in both revenue and expense. Effective January 1, 2018, the exclusion of these taxes from revenue resulted in a decrease in revenue of $12 million and $38 million for the three and nine months ended September 30, 2018, respectively, compared to the same periods in 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.

The Corporation disaggregates revenue by regulatory status, service territory and substantially autonomous utility operations, as disclosed in Note 5 of the Interim Financial Statements. This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer in allocating resources and evaluating 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 of this ASU did not impact the Interim Financial Statements.

Pension and Postretirement Benefit Costs
Effective January 1, 2018, the Corporation adopted ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* which requires current service costs to be disaggregated and grouped in the statement of earnings with other employee compensation costs arising from services rendered. The other components of net periodic benefit costs must be presented separately and outside of operating income. Additionally, only the service cost component is eligible for capitalization. On adoption, the Corporation applied the presentation guidance retrospectively and the capitalization guidance prospectively. This resulted in a retrospective $1 million and $8 million reclassification from Operating Expenses to Other Income, Net for the three and nine months ended September 30, 2017, respectively, in the Interim Financial Statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

Leases
ASU No. 2016-02, *Leases (ASC Topic 842)*, issued in February 2016, is effective for Fortis January 1, 2019 with earlier adoption permitted, 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 plans to select 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 will elect a package of practical expedients that allows it to not reassess whether any expired or existing contract is a lease or contains a lease, the lease classification of any expired or existing leases, and the initial direct costs for any existing leases. Fortis also will elect an additional practical expedient that permits entities to not evaluate existing land easements that were not previously accounted for as leases.

Based on Fortis' assessment to date, leasing activities accounted for as operating leases primarily relate to office facilities and utility property. Ongoing implementation efforts include the evaluation of business processes and controls to support recognition under the new standard and preparation of expanded disclosures. Fortis continues to assess the impact of adoption and monitor standard-setting activities that may affect transition requirements.

Hedging
ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, issued in August 2017, is effective for Fortis January 1, 2019 with earlier adoption permitted and is to be applied as of the beginning of the fiscal year of adoption. 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 existing at the date of adoption, the amendments should be applied as a cumulative-effect adjustment related to eliminating the separate measurement of ineffectiveness to accumulated other comprehensive income with a corresponding adjustment to opening retained earnings. Amended presentation and disclosure guidance is to be applied prospectively. The adoption of this ASU will not have a material impact on the consolidated financial statements and related disclosures.

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.

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 September 30, 2018, the carrying value of long-term debt, including current portion, was $22,599 million (December 31, 2017 - $21,535 million) compared to an estimated fair value of $23,540 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 of the same remaining 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.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the instruments as at the balance sheet dates. The fair value of derivative instruments is the estimate of the amounts that the Corporation would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates. The Corporation's derivatives primarily include energy contracts that are subject to regulatory deferral, as permitted by the regulators, as well as certain limited energy contracts that are not subject to regulatory deferral and cash flow hedges.

Refer to Note 14 to the Corporation's Interim Financial Statements for further details. There were no material changes in the nature and amount of the Corporations' derivative instruments from those disclosed in the Corporation's 2017 Annual MD&A.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Interim Financial Statements requires management to make estimates and judgments, including those related to regulatory decisions, that affect the reported amounts of, and disclosures related to, assets, liabilities, revenues and expenses. Actual results could differ from estimates.

There were no material changes in the nature of the Corporation's critical accounting estimates from those disclosed in the 2017 Annual MD&A.

Contingencies

There were no material changes in the Corporation's contingencies from those disclosed in the 2017 Annual MD&A.

Comparative Figures in the Consolidated Statement of Cash Flows
During the year ended December 31, 2017, the Corporation discovered an immaterial error with respect to the presentation of credit facility borrowings within the financing section of its statement of cash flows. The Corporation evaluated the error and determined that there was no impact to its results of operations or financial position in previously issued financial statements and that the impact was not material to its cash flows in previously issued financial statements. For the three and nine months ended September 30, 2017, the correction resulted in $11 million and $234 million, respectively, which was previously reported within Net Repayments/Borrowings under Committed Credit Facilities, now being reported on a gross basis as Borrowings under Committed Credit Facilities of $659 million and $1,466 million, respectively, and Repayments under Committed Credit Facilities of $648 million and $1,700 million, respectively.

The correction of the error for the periods ended March 31, 2017, June 30, 2017 and September 30, 2017 is detailed below.

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

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. In addition to the above noted correction, comparative figures have been reclassified to comply with the current period presentation.

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 for the three and nine months ended September 30, 2018 and 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				
Periods Ended September 30	**Quarter**		**Year-to-Date**	
($ millions)	**2018**	2017	**2018**	2017
Sale of capacity from Waneta Expansion to FortisBC Electric	**12**	11	**31**	30
Sale of energy from Belize Electric Company Limited to BEL	**8**	11	**26**	25
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**6**	5	**19**	18

As at September 30, 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 inter-segment loans outstanding as at September 30, 2018 and December 31, 2017.

SUMMARY OF QUARTERLY RESULTS

Quarterly information has been obtained from the Corporation's Interim Financial Statements and is provided below. 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 **Quarter Ended**	**Revenue** *($ millions)*	**Net Earnings Attributable to Common Equity Shareholders** *($ millions)*	**Earnings per Common Share** **Basic** *($)*	 **Diluted** *($)*
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
December 31, 2016	2,053	189	0.49	0.49

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

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 of 2017. A discussion of the quarter over quarter variance in financial results is provided in the "Financial Highlights" section of this MD&A.

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 compared to last year at UNS Energy; 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.

December 2017/December 2016: Net earnings attributable to common equity shareholders were $134 million, or $0.32 per common share, for the fourth quarter of 2017 compared to earnings of $189 million, or $0.49 per common share, for the fourth quarter of 2016. The decrease in earnings was driven by lower earnings at ITC, due to the one-time remeasurement of deferred income tax assets and liabilities as a result of U.S. tax reform, partially offset by higher earnings at Aitken Creek associated with unrealized gains on the mark-to-market of natural gas derivatives.

OUTLOOK

Over the long term, Fortis is well positioned to enhance value for shareholders through the execution of its capital expenditure plan, 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 a three and five-year compound annual growth rate 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 organic 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 the long-term sustainable growth in rate base to support continuing growth in earnings and dividends. Fortis has targeted average annual dividend growth of approximately 6% through to 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 November 1, 2018, the Corporation had issued and outstanding 426.6 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 November 1, 2018 is approximately 4.1 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.

FORTIS INC.

Condensed Consolidated Interim Financial Statements
For the three and nine months ended September 30, 2018 and 2017
(Unaudited)

FORTIS INC.

Condensed Consolidated Interim Balance Sheets (Unaudited)

As at

(in millions of Canadian dollars)

	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	**$ 195**	$ 327
Accounts receivable and other current assets (Note 6)	**1,131**	1,131
Prepaid expenses	**110**	79
Inventories	**368**	367
Regulatory assets (Note 7)	**329**	303
Total current assets	**2,133**	2,207
Other assets	**536**	480
Regulatory assets (Note 7)	**2,744**	2,742
Property, plant and equipment, net	**31,727**	29,668
Intangible assets, net	**1,165**	1,081
Goodwill	**11,939**	11,644
Total assets	**$ 50,244**	$ 47,822
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 8)	**$ 39**	$ 209
Accounts payable and other current liabilities	**1,906**	2,053
Regulatory liabilities (Note 7)	**680**	490
Current installments of long-term debt (Note 8)	**930**	705
Current installments of capital lease and finance obligations	**46**	47
Total current liabilities	**3,601**	3,504
Other liabilities	**1,232**	1,210
Regulatory liabilities (Note 7)	**2,921**	2,956
Deferred income taxes	**2,533**	2,298
Long-term debt (Note 8)	**21,533**	20,691
Capital lease and finance obligations (Note 15)	**617**	414
Total liabilities	**32,437**	31,073
Commitments and Contingencies (Note 15)		
Equity		
Common shares [(1)]	**11,808**	11,582
Preference shares	**1,623**	1,623
Additional paid-in capital	**10**	10
Accumulated other comprehensive income	**337**	61
Retained earnings	**2,206**	1,727
Shareholders' equity	**15,984**	15,003
Non-controlling interests	**1,823**	1,746
Total equity	**17,807**	16,749
Total liabilities and equity	**$ 50,244**	$ 47,822

[(1)] *No par value. Unlimited authorized shares; 426.6 million and 421.1 million issued and outstanding as at September 30, 2018 and December 31, 2017, respectively*

See accompanying Notes to Condensed Consolidated Interim Financial Statements

FORTIS INC.

Condensed Consolidated Interim Statements of Earnings (Unaudited)

For the periods ended September 30

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

	Quarter Ended		Year-to-Date	
	2018	2017	**2018**	2017
Revenue (Note 6)	**$ 2,040**	$ 1,901	**$ 6,184**	$ 6,190
Expenses				
Energy supply costs	**574**	478	**1,810**	1,756
Operating expenses	**557**	503	**1,663**	1,649
Depreciation and amortization	**313**	290	**924**	885
Total expenses	**1,444**	1,271	**4,397**	4,290
Operating income	**596**	630	**1,787**	1,900
Other income, net (Note 10)	**23**	22	**50**	70
Finance charges	**245**	225	**724**	686
Earnings before income taxes	**374**	427	**1,113**	1,284
Income tax expense	**52**	106	**135**	314
Net earnings	**$ 322**	$ 321	**$ 978**	$ 970
Net earnings attributable to:				
Non-controlling interests	**$ 30**	$ 27	**$ 90**	$ 92
Preference equity shareholders	**16**	16	**49**	49
Common equity shareholders	**276**	278	**839**	829
	$ 322	$ 321	**$ 978**	$ 970
Earnings per common share (Note 12)				
Basic	**$ 0.65**	$ 0.66	**$ 1.98**	$ 2.00
Diluted	**$ 0.65**	$ 0.66	**$ 1.98**	$ 2.00

See accompanying Notes to Condensed Consolidated Interim Financial Statements

FORTIS INC.

Condensed Consolidated Interim Statements of Comprehensive Income (Unaudited)

For the periods ended September 30

(in millions of Canadian dollars)

	Quarter Ended		Year-to-Date	
	2018	2017	**2018**	2017
Net earnings	**$ 322**	$ 321	**$ 978**	$ 970
Other comprehensive income (loss)				
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	**(235)**	(375)	**315**	(711)
Other, net of tax	**1**	3	**2**	1
	(234)	(372)	**317**	(710)
Comprehensive income (loss)	**$ 88**	$ (51)	**$ 1,295**	$ 260
Comprehensive income (loss) attributable to:				
Non-controlling interests	**$ (1)**	$ 27	**$ 131**	$ 92
Preference equity shareholders	**16**	16	**49**	49
Common equity shareholders	**73**	(94)	**1,115**	119
	$ 88	$ (51)	**$ 1,295**	$ 260

See accompanying Notes to Condensed Consolidated Interim Financial Statements

FORTIS INC.
Condensed Consolidated Interim Statements of Cash Flows (Unaudited)
For the periods ended September 30
(in millions of Canadian dollars)

	Quarter Ended		Year-to-Date	
	2018	2017	**2018**	2017
Operating activities				
Net earnings	**$ 322**	$ 321	**$ 978**	$ 970
Adjustments to reconcile net earnings to net cash provided by operating activities:				
Depreciation - property, plant and equipment	**279**	261	**824**	794
Amortization - intangible assets	**27**	23	**78**	71
Amortization - other	**7**	6	**22**	20
Deferred income tax expense	**62**	110	**123**	284
Accrued employee future benefits	**(6)**	—	**(3)**	10
Equity component of allowance for funds used during construction (Note 10)	**(17)**	(19)	**(47)**	(55)
Other	**16**	16	**75**	5
Change in long-term regulatory assets and liabilities	**56**	102	**58**	93
Change in working capital (Note 13)	**50**	(20)	**(41)**	(202)
Cash from operating activities	**796**	800	**2,067**	1,990
Investing activities				
Capital expenditures - property, plant and equipment	**(744)**	(644)	**(2,123)**	(1,967)
Capital expenditures - intangible assets	**(44)**	(62)	**(142)**	(167)
Contributions in aid of construction	**31**	39	**91**	76
Other	**(26)**	(16)	**(79)**	(85)
Cash used in investing activities	**(783)**	(683)	**(2,253)**	(2,143)
Financing activities				
Proceeds from long-term debt, net of issuance costs	**253**	274	**605**	1,030
Repayments of long-term debt and capital lease and finance obligations	**(54)**	(105)	**(285)**	(140)
Borrowings under committed credit facilities (Note 16)	**1,369**	1,533	**3,731**	5,157
Repayments under committed credit facilities (Note 16)	**(1,433)**	(1,735)	**(3,618)**	(6,132)
Net change in short-term borrowings (Note 16)	**(3)**	90	**20**	100
Issue of common shares, net of costs, and dividends reinvested	**6**	8	**26**	552
Dividends				
Common shares, net of dividends reinvested	**(110)**	(106)	**(340)**	(308)
Preference shares	**(16)**	(16)	**(49)**	(49)
Subsidiary dividends paid to non-controlling interests	**(27)**	(34)	**(67)**	(73)
Other	**3**	4	**23**	11
Cash (used in) from financing activities	**(12)**	(87)	**46**	148
Effect of exchange rate changes on cash and cash equivalents	**(3)**	(9)	**8**	(12)
Change in cash and cash equivalents	**(2)**	21	**(132)**	(17)
Cash and cash equivalents, beginning of period	**197**	231	**327**	269
Cash and cash equivalents, end of period	**$ 195**	$ 252	**$ 195**	$ 252

Supplementary Information to Condensed Consolidated Interim Statements of Cash Flows (Note 13)

See accompanying Notes to Condensed Consolidated Interim Financial Statements

FORTIS INC.

Condensed Consolidated Interim Statements of Changes in Equity (Unaudited)

For the periods ended September 30

(in millions of Canadian dollars)

	Common Shares (*# millions*)	Common Shares	Preference Shares	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	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	**—**	**—**	**—**	**—**	**—**	**888**	**90**	**978**
Other comprehensive income	**—**	**—**	**—**	**—**	**276**	**—**	**41**	**317**
Common shares issued	**5.5**	**226**	**—**	**(1)**	**—**	**—**	**—**	**225**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(67)**	**(67)**
Dividends declared on common shares ($0.85 per share)	**—**	**—**	**—**	**—**	**—**	**(360)**	**—**	**(360)**
Dividends declared on preference shares	**—**	**—**	**—**	**—**	**—**	**(49)**	**—**	**(49)**
Other	**—**	**—**	**—**	**1**	**—**	**—**	**13**	**14**
As at September 30, 2018	**426.6**	**$ 11,808**	**$ 1,623**	**$ 10**	**$ 337**	**$ 2,206**	**$ 1,823**	**$17,807**
As at December 31, 2016	401.5	$ 10,762	$ 1,623	$ 12	$ 745	$ 1,455	$ 1,853	$ 16,450
Net earnings	—	—	—	—	—	878	92	970
Other comprehensive loss	—	—	—	—	(710)	—	—	(710)
Common shares issued	17.9	743	—	(4)	—	—	—	739
Foreign currency translation impacts	—	—	—	—	—	—	(109)	(109)
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(73)	(73)
Dividends declared on common shares ($0.80 per share)	—	—	—	—	—	(333)	—	(333)
Dividends declared on preference shares	—	—	—	—	—	(49)	—	(49)
Other	—	—	—	2	—	—	4	6
As at September 30, 2017	419.4	$ 11,505	$ 1,623	$ 10	$ 35	$ 1,951	$ 1,767	$ 16,891

See accompanying Notes to Condensed Consolidated Interim Financial Statements

1. DESCRIPTION OF BUSINESS

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally a North American electric and gas utility holding company.

Earnings for interim periods may not be indicative of annual results due to the impact of seasonal weather conditions on customer demand and market pricing and the timing and recognition of regulatory decisions. 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.

Entities within the reporting segments that follow operate with substantial autonomy.

Regulated Utilities

ITC: Comprised of ITC Holdings Corp. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company, Michigan Electric Transmission Company, LLC, ITC Midwest LLC and ITC Great Plains, LLC, all operating in the United States. Fortis owns 80.1% of ITC and an affiliate of GIC Private Limited owns a 19.9% minority interest.

UNS Energy: Comprised of UNS Energy Corporation, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. and UNS Gas, Inc., all operating in the United States.

Central Hudson: Represents Central Hudson Gas & Electric Corporation, operating in the United States.

FortisBC Energy: Represents FortisBC Energy Inc., operating in Canada.

FortisAlberta: Represents FortisAlberta Inc., operating in Canada.

FortisBC Electric: Represents FortisBC Inc., operating in Canada.

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; 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").

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") in British Columbia.

Corporate and Other: Captures expenses and revenues not specifically related to any reportable segment and those business operations that are below the required threshold for segmented reporting, including net expenses of Fortis and non-regulated holding companies.

2. REGULATORY MATTERS

Regulation of the Corporation's utilities is generally consistent with that disclosed in its 2017 annual audited consolidated financial statements. A summary of significant regulatory developments year-to-date 2018 follows.

U.S. Tax Reform

The Corporation's U.S. utilities are working with their respective regulators to return to customers the net income tax savings resulting from U.S. tax reform.

ITC: In April 2018 ITC reposted formula rates charged to customers of its Midcontinent Independent System Operator ("MISO") regulated operating subsidiaries retroactive to January 1, 2018, as approved by the Federal Energy Regulatory Commission ("FERC"). As at September 30, 2018, the amounts owing had been substantially returned to customers.

UNS Energy: In April 2018 the Arizona Corporation Commission ("ACC") 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 September 30, 2018, a regulatory liability of $3 million (US$2 million) was recognized for amounts to be returned to customers during the remainder of 2018. 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. The proposal is currently being reviewed by FERC.

Central Hudson: In June 2018, as part of its approval of a joint proposal, discussed below, the New York Public Service Commission ("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 September 30, 2018, a regulatory liability of $12 million (US$10 million) was recognized related to the income tax savings realized in the first six months of 2018. As approved by the PSC, the refund of this regulatory liability to customers will be determined as part of a future regulatory proceeding.

ITC

Independence Incentive Adders: In April 2018 a third-party complaint was filed with FERC challenging independence incentive adders that were included in transmission rates charged by ITC's MISO-regulated operating subsidiaries. Independence incentive adders were established to encourage transmission investment and recognize that ITC's operating subsidiaries are independent, dedicated transmission-only operations, with no affiliation to market participants in their regions. The adders allowed up to 0.50% or 1.00% to be added to the authorized return on equity ("ROE"), subject to any ROE cap established by FERC. On October 18, 2018, FERC issued an order in respect of this matter reducing the adders for each of the MISO-regulated operating subsidiaries to 0.25% effective April 20, 2018. On October 22, 2018, MISO filed a motion requesting an extension to January 17, 2019 to issue refunds. The resolution of this proceeding is not expected to have a material adverse impact on results of operations, cash flows or financial position.

ROE Complaints: On October 16, 2018, in response to complaints challenging the methodology used by FERC in setting the regional base ROE for ISO New England transmission owners, FERC issued an order proposing a new methodology for determining (i) when an existing ROE is no longer just and reasonable, and (ii) the regional base ROE if an existing ROE is found to no longer be just and reasonable. If finalized, this proposed methodology will be used to address ROE complaints currently pending before FERC, including ITC's outstanding ROE complaints.

Central Hudson

In June 2018 the 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 Proceeding: Oral hearings to determine the ROE and capital structure for 2018, 2019 and 2020 were completed in March 2018. In August 2018 the Alberta Utilities Commission ("AUC") approved an allowed ROE of 8.50% on a capital structure of 37% common equity for 2018, 2019 and 2020, unchanged from 2017.

Next Generation Performance-Based Rate Setting Proceeding: In March 2018 the AUC approved the Company's 2018 distribution rates, on an interim basis, until true-up amounts are finalized. New rates were effective January 1, 2018 with collection from customers effective April 1, 2018. Key provisions included an increase of approximately 5.5% in the distribution component of rates.

FortisAlberta is pursuing options to appeal certain elements of the rate-setting design for the second term of performance-based rate setting ("PBR").

3. ACCOUNTING POLICIES

These condensed consolidated interim financial statements ("Interim Financial Statements") have been prepared in accordance with accounting principles generally accepted in the United States of America and are in Canadian dollars unless otherwise noted.

These Interim Financial Statements are comprised of the accounts of Fortis and its wholly owned subsidiaries and controlling ownership interests. All inter-company balances and transactions have been eliminated on consolidation, except as disclosed in Note 5.

These Interim Financial Statements do not include all of the disclosures required in the annual financial statements and should be read in conjunction with the Corporation's 2017 annual audited consolidated financial statements. In management's opinion, these Interim Financial Statements include all adjustments that are of a normal recurring nature, necessary for fair presentation.

The preparation of the Interim Financial Statements requires management to make estimates and judgments, including those related to regulatory decisions, that affect the reported amounts of, and disclosures related to, assets, liabilities, revenues and expenses. Actual results could differ from estimates.

The accounting policies applied herein are consistent with those outlined in the Corporation's 2017 annual audited consolidated financial statements, except as described below.

New Accounting Policies

Revenue
Effective January 1, 2018, Fortis adopted Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers*, which clarifies the principles for recognizing revenue and requires additional disclosures. Fortis adopted the new 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 (Note 6). Upon adoption, there were no adjustments to the opening balance of retained earnings.

Most of the Corporation's 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. 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 Alberta Electric System Operator. These services include the collection of transmission revenue from its customers, which is achieved through invoicing the customers' retailers through the transmission component of its regulator-approved rates. FortisAlberta reports revenue and expenses related to transmission services on a net basis.

Electricity, gas and transmission service revenue includes an unbilled revenue estimate for energy consumed or services provided since the last meter reading that have not been billed at the end of the accounting 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 rates.

The Corporation estimates variable consideration at the most likely amount and reassesses its estimate 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 the Corporation is certain that it will be entitled to the consideration.

The Corporation's revenue excludes sales and municipal taxes collected from customers. Prior to the adoption of ASC Topic 606, Central Hudson recognized sales tax and FortisAlberta recognized municipal tax on a gross basis, in both revenue and expense. Effective January 1, 2018, the exclusion of these taxes from revenue resulted in a decrease in revenue of $12 million and $38 million for the three and nine months ended September 30, 2018, respectively, compared to the same periods in 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.

The Corporation disaggregates revenue by regulatory status, service territory and substantially autonomous utility operations (Note 5). This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer ("CEO") in allocating resources and evaluating 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 these financial statement notes, grouped by measurement category and form. Adoption of this ASU did not impact the Interim Financial Statements.

Pension and Postretirement Benefit Costs
Effective January 1, 2018, the Corporation adopted ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* which requires current service costs to be disaggregated and grouped in the statement of earnings with other employee compensation costs arising from services rendered. The other components of net periodic benefit costs must be presented separately and outside of operating income. Additionally, only the service cost component is eligible for capitalization. On adoption, the Corporation applied the presentation guidance retrospectively and the capitalization guidance prospectively. This resulted in a retrospective $1 million and $8 million reclassification from Operating Expenses to Other Income, Net for the three and nine months ended September 30, 2017, respectively, in these Interim Financial Statements.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

Leases

ASU No. 2016-02, *Leases (ASC Topic 842)*, issued in February 2016, is effective for Fortis January 1, 2019 with earlier adoption permitted, 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 plans to select 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 will elect a package of practical expedients that allows it to not reassess whether any expired or existing contract is a lease or contains a lease, the lease classification of any expired or existing leases, and the initial direct costs for any existing leases. Fortis also will elect an additional practical expedient that permits entities to not evaluate existing land easements that were not previously accounted for as leases.

Based on Fortis' assessment to date, leasing activities accounted for as operating leases primarily relate to office facilities and utility property. Ongoing implementation efforts include the evaluation of business processes and controls to support recognition under the new standard and preparation of expanded disclosures. Fortis continues to assess the impact of adoption and monitor standard-setting activities that may affect transition requirements.

Hedging

ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, issued in August 2017, is effective for Fortis January 1, 2019 with earlier adoption permitted and is to be applied as of the beginning of the fiscal year of adoption. 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 existing at the date of adoption, the amendments should be applied as a cumulative-effect adjustment related to eliminating the separate measurement of ineffectiveness to accumulated other comprehensive income with a corresponding adjustment to opening retained earnings. Amended presentation and disclosure guidance is to be applied prospectively. The adoption of this ASU will not have a material impact on the consolidated financial statements and related disclosures.

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.

5. SEGMENTED INFORMATION

Fortis segments its business based on regulatory status, service territory and substantially autonomous utility operations. This represents the information used by the Corporation's President and CEO in deciding how to allocate resources and evaluate performance. Segment performance is evaluated based on net earnings attributable to common equity shareholders.

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

	REGULATED								NON-REGULATED			
Quarter Ended September 30, 2018 *($ 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	386	687	214	161	155	96	307	**2,006**	**37**	**—**	**(3)**	**2,040**
Energy supply costs	—	280	66	32	—	33	162	**573**	**1**	**—**	**—**	**574**
Operating expenses	114	152	100	70	42	24	43	**545**	**11**	**4**	**(3)**	**557**
Depreciation and amortization	59	70	18	55	48	15	40	**305**	**8**	**—**	**—**	**313**
Operating income	213	185	30	4	65	24	62	**583**	**17**	**(4)**	**—**	**596**
Other income, net	11	6	1	2	—	1	(1)	**20**	**—**	**3**	**—**	**23**
Finance charges	73	26	10	34	25	10	19	**197**	**1**	**47**	**—**	**245**
Income tax expense	33	30	4	(7)	1	3	7	**71**	**1**	**(20)**	**—**	**52**
Net earnings	118	135	17	(21)	39	12	35	**335**	**15**	**(28)**	**—**	**322**
Non-controlling interests	21	—	—	1	—	—	5	**27**	**3**	**—**	**—**	**30**
Preference share dividends	—	—	—	—	—	—	—	**—**	**—**	**16**	**—**	**16**
Net earnings attributable to common equity shareholders	97	135	17	(22)	39	12	30	**308**	**12**	**(44)**	**—**	**276**
Goodwill	7,922	1,783	582	913	227	235	250	**11,912**	**27**	**—**	**—**	**11,939**
Total assets	18,606	9,415	3,325	6,497	4,646	2,234	3,940	**48,663**	**1,551**	**87**	**(57)**	**50,244**
Capital expenditures	249	150	68	118	102	27	68	**782**	**5**	**1**	**—**	**788**
Quarter Ended September 30, 2017 *($ millions)*												
Revenue	376	599	197	156	153	93	283	1,857	47	—	(3)	1,901
Energy supply costs	—	199	54	38	—	33	154	478	—	—	—	478
Operating expenses	103	145	94	65	47	21	42	517	12	(23)	(3)	503
Depreciation and amortization	54	62	16	49	47	16	38	282	8	—	—	290
Operating income	219	193	33	4	59	23	49	580	27	23	—	630
Other income, net	10	2	2	6	(1)	1	(1)	19	1	2	—	22
Finance charges	63	24	10	28	23	10	18	176	2	47	—	225
Income tax expense	58	59	10	(4)	—	3	6	132	2	(28)	—	106
Net earnings	108	112	15	(14)	35	11	24	291	24	6	—	321
Non-controlling interests	19	—	—	1	—	—	4	24	3	—	—	27
Preference share dividends	—	—	—	—	—	—	—	—	—	16	—	16
Net earnings attributable to common equity shareholders	89	112	15	(15)	35	11	20	267	21	(10)	—	278
Goodwill	7,655	1,724	563	913	227	235	244	11,561	27	—	—	11,588
Total assets	17,349	8,463	3,033	6,266	4,288	2,177	3,691	45,267	1,578	72	(72)	46,845
Capital expenditures	213	99	53	132	109	26	68	700	6	—	—	706

	REGULATED								NON-REGULATED			
Year-to-Date September 30, 2018 *($ 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	1,114	1,661	690	816	439	297	1,040	**6,057**	**134**	**—**	**(7)**	**6,184**
Energy supply costs	—	628	248	216	—	95	621	**1,808**	**2**	**—**	**—**	**1,810**
Operating expenses	326	448	302	221	123	74	131	**1,625**	**30**	**15**	**(7)**	**1,663**
Depreciation and amortization	172	202	53	165	143	45	119	**899**	**24**	**1**	**—**	**924**
Operating income	616	383	87	214	173	83	169	**1,725**	**78**	**(16)**	**—**	**1,787**
Other income, net	32	12	6	4	—	2	(1)	**55**	**—**	**(5)**	**—**	**50**
Finance charges	211	76	31	101	74	30	57	**580**	**4**	**140**	**—**	**724**
Income tax expense	110	53	12	33	1	12	18	**239**	**3**	**(107)**	**—**	**135**
Net earnings	327	266	50	84	98	43	93	**961**	**71**	**(54)**	**—**	**978**
Non-controlling interests	58	—	—	1	—	—	10	**69**	**21**	**—**	**—**	**90**
Preference share dividends	—	—	—	—	—	—	—	**—**	**—**	**49**	**—**	**49**
Net earnings attributable to common equity shareholders	269	266	50	83	98	43	83	**892**	**50**	**(103)**	**—**	**839**
Goodwill	7,922	1,783	582	913	227	235	250	**11,912**	**27**	**—**	**—**	**11,939**
Total assets	18,606	9,415	3,325	6,497	4,646	2,234	3,940	**48,663**	**1,551**	**87**	**(57)**	**50,244**
Capital expenditures	717	419	175	318	325	81	193	**2,228**	**36**	**1**	**—**	**2,265**
Year-to-Date September 30, 2017 *($ millions)*												
Revenue	1,179	1,609	661	832	448	291	1,016	6,036	162	1	(9)	6,190
Energy supply costs	—	545	203	292	—	100	616	1,756	1	—	(1)	1,756
Operating expenses	329	442	302	210	147	65	129	1,624	35	(2)	(8)	1,649
Depreciation and amortization	164	195	50	149	142	47	113	860	24	1	—	885
Operating income	686	427	106	181	159	79	158	1,796	102	2	—	1,900
Other income, net	30	17	4	16	1	1	(2)	67	1	3	(1)	70
Finance charges	193	76	31	86	69	28	56	539	4	144	(1)	686
Income tax expense	190	126	31	22	—	10	17	396	9	(91)	—	314
Net earnings	333	242	48	89	91	42	83	928	90	(48)	—	970
Non-controlling interests	60	—	—	1	—	—	10	71	21	—	—	92
Preference share dividends	—	—	—	—	—	—	—	—	—	49	—	49
Net earnings attributable to common equity shareholders	273	242	48	88	91	42	73	857	69	(97)	—	829
Goodwill	7,655	1,724	563	913	227	235	244	11,561	27	—	—	11,588
Total assets	17,349	8,463	3,033	6,266	4,288	2,177	3,691	45,267	1,578	72	(72)	46,845
Capital expenditures	725	347	156	329	304	72	188	2,121	13	—	—	2,134

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 for the three and nine months ended September 30, 2018 and 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.

	Quarter Ended September 30		Year-to-Date September 30	
($ millions)	**2018**	2017	**2018**	2017
Sale of capacity from Waneta Expansion to FortisBC Electric	**12**	11	**31**	30
Sale of energy from Belize Electric Company Limited to BEL	**8**	11	**26**	25
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**6**	5	**19**	18

As at September 30, 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 inter-segment loans outstanding as at September 30, 2018 and December 31, 2017.

6. REVENUE

	Quarter Ended September 30		Year-to-Date September 30	
($ millions)	**2018**	2017	**2018**	2017
Electric and gas revenue				
United States				
ITC	**456**	455	**1,197**	1,230
UNS Energy	**645**	557	**1,507**	1,464
Central Hudson	**225**	188	**721**	610
Canada				
FortisBC Energy	**155**	150	**789**	868
FortisAlberta	**144**	152	**420**	445
FortisBC Electric	**82**	82	**262**	255
Newfoundland Power	**108**	108	**475**	489
Maritime Electric	**49**	46	**151**	144
FortisOntario	**51**	49	**148**	150
Caribbean				
Caribbean Utilities	**70**	58	**184**	165
FortisTCI	**21**	18	**58**	56
Total electric and gas revenue	**2,006**	1,863	**5,912**	5,876
Other services revenue [(1)]	**92**	92	**301**	291
Revenue from contracts with customers	**2,098**	1,955	**6,213**	6,167
Alternative revenue	**(69)**	(82)	**(66)**	(84)
Other revenue	**11**	28	**37**	107
Total revenue	**2,040**	1,901	**6,184**	6,190

[(1)] Includes $59 million and $168 million from regulated operations for the three and nine months ended September 30, 2018, respectively ($50 million and $150 million for the three and nine months ended September 30, 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 below.

ITC's formula rates include an annual true-up mechanism that compares actual revenue requirements to billed revenue and any over- or under-collections are accrued as a regulatory asset or liability and reflected in future rates within a two-year period. 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 are reflected in non-fuel base rates.

At FortisBC Energy and FortisBC Electric, an earnings sharing mechanism allows for a 50/50 sharing of variances from operating and maintenance expenses and capital expenditures that were 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, which are either refunded to or recovered from customers in rates within two years.

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

Accounts Receivable and Other Current Assets

	As at	
($ millions)	**September 30, 2018**	December 31, 2017
Trade accounts receivable	**498**	460
Unbilled accounts receivable	**472**	562
Allowance for doubtful accounts	**(33)**	(31)
Total accounts receivable	**937**	991
Income tax receivable	**54**	8
Other	**140**	132
Total accounts receivable and other current assets	**1,131**	1,131

7. REGULATORY ASSETS AND LIABILITIES

Detailed information about the Corporation's regulatory assets and liabilities is provided in Note 8 to the Corporation's 2017 annual audited consolidated financial statements. A summary follows.

	As at	
($ millions)	**September 30, 2018**	December 31, 2017
Regulatory assets		
Deferred income taxes	**1,434**	1,403
Employee future benefits	**480**	510
Deferred energy management costs	**212**	200
Deferred lease costs	**116**	104
Deferred operating overhead costs	**100**	91
Generation early retirement costs	**95**	105
Rate stabilization accounts	**81**	95
Manufactured gas plant site remediation deferral	**72**	75
Derivative instruments	**69**	87
Other regulatory assets	**414**	375
Total regulatory assets	**3,073**	3,045
Less: Current portion	**(329)**	(303)
Long-term regulatory assets	**2,744**	2,742
Regulatory liabilities		
Deferred income taxes	**1,482**	1,484
Asset removal cost provision	**1,136**	1,095
Rate stabilization accounts	**348**	254
Return on equity refund liability	**192**	182
Energy efficiency liability	**99**	82
Renewable energy surcharge	**80**	66
Electric and gas moderator account	**60**	58
Employee future benefits	**39**	47
Other regulatory liabilities (1)	**165**	178
Total regulatory liabilities	**3,601**	3,446
Less: Current portion	**(680)**	(490)
Long-term regulatory liabilities	**2,921**	2,956

(1) Includes a $21 million provision reflecting income tax savings, as a result of U.S. tax reform

8. LONG-TERM DEBT

($ millions)	As at September 30, 2018	December 31, 2017
Long-term debt	**21,601**	20,864
Credit facility borrowings	**998**	671
Total long-term debt	**22,599**	21,535
Less: Deferred financing costs and debt discounts	**(136)**	(139)
Less: Current installments of long-term debt	**(930)**	(705)
	21,533	20,691

In March 2018 ITC issued 35-year US$225 million first mortgage bonds at 4.00%. The net proceeds were used to repay maturing long-term debt, repay credit facility borrowings, finance capital expenditures and for general corporate purposes.

In February 2018 FortisTCI issued 5-year US$25 million unsecured notes at a floating interest rate of a one-month LIBOR plus a spread of 1.75%. In September 2018 FortisTCI entered into a 7-year US$10 million unsecured non-revolving term loan credit agreement with a floating interest rate of a one-month LIBOR plus a spread of 1.75%. As at September 30, 2018, borrowings under the term loan credit agreement were US$5 million. The net proceeds were used to repay a hurricane-related emergency standby loan and for general corporate purposes.

In June 2018 Central Hudson issued 30-year US$25 million unsecured notes at 4.27%. The net proceeds were used for general corporate purposes.

In August 2018 FortisOntario issued 30-year $100 million unsecured notes at 4.10%. The net proceeds were used to repay maturing long-term debt and for general corporate purposes.

In September 2018 FortisAlberta issued 30-year $150 million unsecured debentures at 3.73%. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

Credit Facilities

As at September 30, 2018, the Corporation and its subsidiaries had consolidated credit facilities of approximately $5.0 billion, of which approximately $3.9 billion was unused, including $1.1 billion unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with large banks in Canada and the United States, with no one bank holding more than 20% of these facilities. Approximately $4.8 billion of the total credit facilities are committed facilities with maturities ranging from 2019 through 2023.

Credit facilities are summarized below.

($ millions)	Regulated Utilities	Corporate and Other	As at September 30, 2018	December 31, 2017
Total credit facilities	3,648	1,385	**5,033**	4,952
Credit facilities utilized:				
Short-term borrowings [(1)]	(37)	(2)	**(39)**	(209)
Long-term debt (including current portion) [(2)]	(762)	(236)	**(998)**	(671)
Letters of credit outstanding	(69)	(55)	**(124)**	(129)
Credit facilities unutilized	2,780	1,092	**3,872**	3,943

(1) The weighted average interest rate was approximately 3.8% (December 31, 2017 - 1.8%).
(2) The weighted average interest rate was approximately 3.0% (December 31, 2017 - 2.5%). The current portion was $552 million (December 31, 2017 - $312 million).

Borrowings under long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods. There were no material changes in credit facilities from that disclosed in the Corporation's 2017 annual audited consolidated financial statements.

9. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans and defined contribution pension plans, including group Registered Retirement Savings Plans and group 401(k) plans, for employees. The Corporation and certain subsidiaries also offer other post-employment benefit ("OPEB") plans for qualifying employees. The net benefit cost is detailed below.

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2018**	2017	**2018**	2017
Quarter Ended September 30				
Components of net benefit cost:				
Service costs	**21**	19	**8**	6
Interest costs	**29**	27	**5**	6
Expected return on plan assets	**(40)**	(37)	**(4)**	(4)
Amortization of actuarial losses	**12**	11	**—**	—
Amortization of past service credits/plan amendments	**—**	—	**(2)**	(3)
Regulatory adjustments	**(1)**	1	**1**	2
Net benefit cost	**21**	21	**8**	7
Year-to-Date September 30				
Components of net benefit cost:				
Service costs	**62**	58	**23**	20
Interest costs	**85**	85	**17**	19
Expected return on plan assets	**(120)**	(113)	**(12)**	(11)
Amortization of actuarial losses	**36**	34	**—**	1
Amortization of past service credits/plan amendments	**—**	—	**(7)**	(9)
Regulatory adjustments	**(1)**	1	**4**	4
Net benefit cost	**62**	65	**25**	24

For the three and nine months ended September 30, 2018, the Corporation expensed $9 million and $29 million, respectively, ($8 million and $28 million for the three and nine months ended September 30, 2017, respectively) related to defined contribution pension plans.

10. OTHER INCOME, NET

Other income, net of expenses, includes the equity component of allowance for funds used during construction of $17 million and $47 million for the three and nine months ended September 30, 2018, respectively ($19 million and $55 million for the three and nine months ended September 30, 2017, respectively).

11. INCOME TAXES

For the three months ended September 30, 2018 and 2017, the Corporation's effective tax rates were 14% and 25%, respectively. For the nine months ended September 30, 2018 and 2017, the Corporation's effective tax rates were 12% and 24%, respectively. The decrease in the effective tax rate was primarily driven by the reduction in the U.S. federal corporate tax rate from 35% to 21%, effective January 1, 2018. On a year-to-date basis, the decrease was also due to a one-time $30 million remeasurement of the Corporation's deferred income tax liabilities, which resulted from an election to file a consolidated state income tax return.

12. EARNINGS PER COMMON SHARE

Diluted earnings per share ("EPS") was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

	2018			2017		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares *(# millions)***	**EPS**	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS
Quarter Ended September 30						
Basic EPS	**276**	**425.6**	**$ 0.65**	278	418.6	$ 0.66
Potential dilutive effect of stock options	**—**	**0.6**		—	0.7	
Diluted EPS	**276**	**426.2**	**$ 0.65**	278	419.3	$ 0.66
Year-to-Date September 30						
Basic EPS	**839**	**423.8**	**$ 1.98**	829	413.9	$ 2.00
Potential dilutive effect of stock options	**—**	**0.6**		—	0.7	
Diluted EPS	**839**	**424.4**	**$ 1.98**	829	414.6	$ 2.00

13. SUPPLEMENTARY CASH FLOW INFORMATION

	Quarter Ended September 30		Year-to-Date September 30	
($ millions)	**2018**	2017	**2018**	2017
Change in working capital:				
Accounts receivable and other current assets	**(23)**	23	**9**	29
Prepaid expenses	**(49)**	(61)	**(29)**	(50)
Inventories	**(28)**	(36)	**5**	(25)
Regulatory assets - current portion	**(10)**	15	**(33)**	2
Accounts payable and other current liabilities	**126**	14	**(39)**	(7)
Regulatory liabilities - current portion	**34**	25	**46**	(151)
	50	(20)	**(41)**	(202)
Non-cash investing and financing activities:				
Accrued capital expenditures	**350**	295	**350**	295
Gila River generating station Unit 2 capital lease	**211**	—	**211**	—
Common share dividends reinvested	**71**	61	**200**	186
Contributions in aid of construction	**10**	32	**10**	32
Exercise of stock options into common shares	**—**	—	**1**	4

14. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivative Instruments

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

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

Cash flows associated with the settlement of all derivative instruments are included in operating activities on 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 parties.

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 September 30, 2018, unrealized losses of $69 million (December 31, 2017 - $87 million) were recognized as regulatory assets and unrealized gains of $17 million (December 31, 2017 - $2 million) were recognized as regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral
UNS Energy holds wholesale trading contracts that qualify as derivative instruments to fix power prices and realize potential margin, of which 10% of any realized gains are shared with customers through 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, to capture natural gas price spreads, and to 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 the three and nine months ended September 30, 2018, unrealized losses of $10 million and $31 million, respectively, (unrealized gains of $4 million and $12 million for the three and nine months ended September 30, 2017, respectively) were recognized in earnings.

Foreign exchange contracts
The Corporation holds US dollar foreign exchange contracts to help mitigate exposure to volatility of foreign exchange rates. The contracts expire in 2018 and 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 the three and nine months ended September 30, 2018, unrealized gains of $4 million and unrealized losses of $3 million, respectively, (nil for the three and nine months ended September 30, 2017) were recognized in earnings.

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 rates.

Unrealized gains and losses associated with changes in the fair value of this interest rate swap, which was designated as 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 twelve 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 the three and nine months ended September 30, 2018, unrealized losses of nil and $3 million, respectively, (unrealized loss of $1 million for the three and nine months ended September 30, 2017) were recognized in earnings.

Other investments
ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for selected employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses on these funds are recognized in earnings. During the three and nine months ended September 30, 2018, unrealized gains of less than $1 million (unrealized gains of less than $1 million for the three and nine months ended September 30, 2017) were recognized in earnings.

Recurring Fair Value Measures

The following table presents the fair value of assets and liabilities that are accounted for at fair value on a recurring basis.

($ millions)	**Level 1 (1)**	**Level 2 (1)**	**Level 3 (1)**	**Total**
As at September 30, 2018				
Assets				
Energy contracts subject to regulatory deferral (2) (3)	**—**	**27**	**4**	**31**
Energy contracts not subject to regulatory deferral (2)	**—**	**7**	**4**	**11**
Other investments (4)	**84**	**—**	**—**	**84**
	84	**34**	**8**	**126**
Liabilities				
Energy contracts subject to regulatory deferral (3) (5)	**—**	**(78)**	**(5)**	**(83)**
Energy contracts not subject to regulatory deferral (5)	**—**	**(3)**	**—**	**(3)**
Foreign exchange contracts, interest rate and total return swaps (6)	**(3)**	**(1)**	**—**	**(4)**
	(3)	**(82)**	**(5)**	**(90)**

($ 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"

Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one hierarchical fair value to another. There were no transfers between levels during the nine months ended September 30, 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, 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.

	Quarter Ended September 30		Year-to-Date September 30	
($ millions)	**2018**	2017	**2018**	2017
Balance, beginning of period	**9**	(4)	**3**	2
Realized losses	**—**	(6)	**—**	(16)
Unrealized gains	**7**	4	**15**	—
Settlements	**(13)**	1	**(15)**	9
Balance, end of period	**3**	(5)	**3**	(5)

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.

($ millions)	Gross Amount Recognized in Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Received / Posted	Net Amount
As at September 30, 2018				
Energy contracts				
Derivative assets	**42**	**19**	**6**	**17**
Derivative liabilities	**(86)**	**(19)**	**—**	**(67)**
As at December 31, 2017				
Energy contracts				
Derivative assets	51	17	7	27
Derivative liabilities	(107)	(17)	—	(90)

Volume of Derivative Activity

As at September 30, 2018, the Corporation had a variety of energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

	As at	
	September 30, 2018	December 31, 2017
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**830**	1,291
Electricity power purchase contracts *(GWh)*	**773**	761
Gas swap contracts *(PJ)*	**221**	216
Gas supply contract premiums *(PJ)*	**287**	219
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**2,076**	2,387
Gas swap contracts *(PJ)*	**36**	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 66% 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 derivative instruments. 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 derivative instruments 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 $105 million as of September 30, 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 September 30, 2018, US$3,408 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$7,884 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 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 September 30, 2018, the carrying value of long-term debt, including current portion, was $22,599 million (December 31, 2017 - $21,535 million) compared to an estimated fair value of $23,540 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 of the same remaining 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.

15. COMMITMENTS AND CONTINGENCIES

Commitments

There were no material changes in commitments from that disclosed in the Corporation's 2017 annual audited consolidated financial statements, except as follows.

In March 2018 Maritime Electric extended its power purchase agreement with New Brunswick Power from March 2019 to February 2024, increasing the total commitment under this agreement by approximately $262 million as at September 30, 2018.

In May 2018, following the acquisition of Gila River generating station Units 1 and 2 by a third party with whom UNS Energy has a power purchase agreement, UNS Energy recorded an increase of US$164 million to capital lease obligations to reflect the anticipated exercising of UNS Energy's option to purchase Unit 2 in December 2019.

Contingencies

In April 2013 FortisBC Holdings Inc. ("FHI") and Fortis were named as defendants in an action in the Supreme Court of British Columbia 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 April 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 in the Interim Financial Statements as the outcome cannot yet be reasonably determined.

16. COMPARATIVE FIGURES

The Corporation revised a line item within the financing activities section of its statement of cash flows for the three and nine months ended September 30, 2017 to correct an immaterial error in the presentation of credit facility borrowings. The error had no impact on the results of operations or financial position and no material impact to cash flows in previously issued financial statements. The correction resulted in $11 million and $234 million for the three and nine months ended September 30, 2017, respectively, previously reported within Net Repayments/Borrowings under Committed Credit Facilities, now being reported on a gross basis as Borrowings under Committed Credit Facilities of $659 million and $1,466 million, respectively, and Repayments under Committed Credit Facilities of $648 million and $1,700 million, respectively.

Effective January 1, 2018, the Corporation elected to present, on the statement of cash flows, borrowings and repayments under committed credit facilities on a gross basis and continue to present borrowings and repayments under uncommitted or demand facilities on a net basis as Net Change in Short-Term Borrowings. Comparative figures were reclassified to conform with the current presentation.

Comparative figures were reclassified to conform with the revised segmentation described in Note 5 and to reflect the retrospective adoption of ASU 2017-07 as described in Note 3.

Expected Dividend* and Earnings Release Dates

Earnings Release Dates

February 15, 2019	May 1, 2019
August 2, 2019	November 1, 2019

Dividend Record Dates

November 20, 2018	February 15, 2019
May 21, 2019	August 20, 2019

Dividend Payment Dates

December 1, 2018	March 1, 2019
June 1, 2019	September 1, 2019

** The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Registrar and Transfer Agent (Canada)
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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

Co-Registrar and Co-Transfer Agent (USA)
Computershare Trust Company N.A.
Att: Stock Transfer Department
Overnight Mail Delivery:
250 Royall Street, Canton MA 02021
Regular Mail Delivery:
P.O. Box 43078, Providence, RI 02940-3070

Share Listings

The Common Shares; 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 Toronto Stock Exchange under the ticker symbols FTS, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively. The Common Shares are also listed on the New York Stock Exchange and trade under the ticker symbol FTS.

Fortis Common Shares (CDN$) Quarter Ended September 30		
	2018	**2017**
High	**43.65**	**46.43**
Low	**41.67**	**43.98**
Close	**41.88**	**44.78**

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