2017

FORTIS INC.

ANNUAL REPORT

Investing in Our Networks


British Columbia
Alberta
Newfoundland and Labrador
Prince Edward Island
Ontario
New York
Minnesota
Michigan
Iowa
Illinois
Kansas
Missouri
Oklahoma
Arizona
Turks and Caicos Islands
Cayman Islands
Belize
REGULATED ELECTRIC
REGULATED GAS
FERC-REGULATED ELECTRIC TRANSMISSION
LONG-TERM CONTRACTED HYDRO GENERATION
NATURAL GAS STORAGE FACILITY

FORTIS INC.

Quick Facts

BASED IN
ST. JOHN'S, NEWFOUNDLAND AND LABRADOR

10 UTILITY OPERATIONS in Canada, the U.S. and the Caribbean

8,500 EMPLOYEES STRONG

$48 BILLION IN TOTAL ASSETS

2 MILLION ELECTRIC UTILITY CUSTOMERS

1.2 MILLION GAS UTILITY CUSTOMERS

$19.4 BILLION MARKET CAP
(as of December 31, 2017)

TSX/NYSE:FTS

Highly Regulated, Low-Risk and Diversified Utility Business

Regulated

Utility	Customers Electric (#)	Customers Gas (#)	Employees (#)	Peak Demand Electric (MW)	Peak Demand Gas (TJ)	Sales Electric (GWh)	Volumes Gas (PJ)	Earnings ($M)	Total Assets ($B)	2018F (1) Midyear Rate Base ($B)	2018F (1) Capital Program ($M)
ITC (2)	–	–	669	22,179	–	–	–	272	17.6	7.7	863
UNS Energy	518,000	156,000	2,024	3,378	105	14,971	13	270	8.6	4.8	686
Central Hudson	300,000	80,000	1,004	1,034	144	4,891	22	70	3.2	1.7	275
FortisBC (3)	172,000	1,008,000	2,229	731	1,336	3,305	221	209	8.6	5.6	566
FortisAlberta	556,000	–	1,116	2,725	–	17,018	–	120	4.5	3.4	407
Eastern Canadian (4)	412,000	–	989	1,945	–	8,355	–	64	2.5	1.8	155
Caribbean Electric (5)	44,000	–	380	142	–	841	–	34	1.3	1.0	152
Total	**2,002,000**	**1,244,000**	**8,411**	**32,134**	**1,585**	**49,381**	**256**	**1,039**	**46.3**	**26**	**3,104**

(1) Forecast

(2) Data includes 100% of ITC's operations except for earnings, which represent ITC's contribution to consolidated earnings of Fortis based on the Corporation's 80.1% ownership interest.

(3) Includes FortisBC Energy and FortisBC Electric.

(4) Includes Newfoundland Power, Maritime Electric, FortisOntario and the Corporation's 49% equity investment in Wataynikaneyap Power Limited Partnership.

(5) Includes Caribbean Utilities and Fortis Turks and Caicos. Data includes 100% of Caribbean Utilities' operations except for earnings, which represent Caribbean Utilities' contribution to consolidated earnings of Fortis based on the Corporation's approximate 60% ownership interest. Also includes the Corporation's 33% equity investment in Belize Electricity.

Non-Regulated

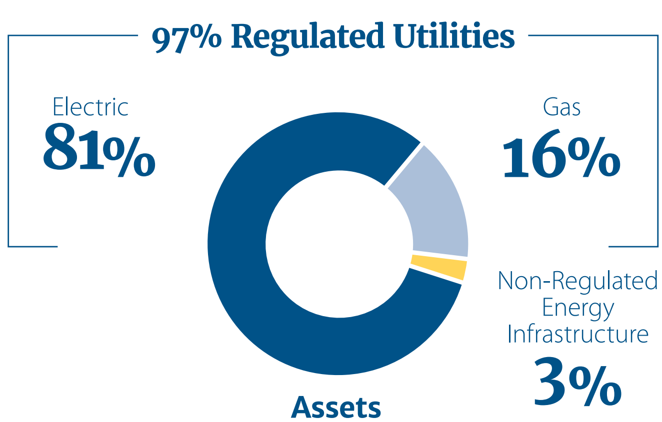
	Generating Capacity (MW)	Employees (#)	Sales Energy (GWh)	Earnings ($M)	Total Assets ($B)	2018F (1) Capital Program ($M)
Non-Regulated Energy Infrastructure (2)	391	66	918	94	1.6	49

(1) Forecast

(2) Comprised of investments in British Columbia, Belize and Ontario.

All financial information is presented in Canadian dollars.
Information is for the fiscal year ended December 31, 2017 unless otherwise indicated.

Total Assets of $48 Billion as of December 31, 2017



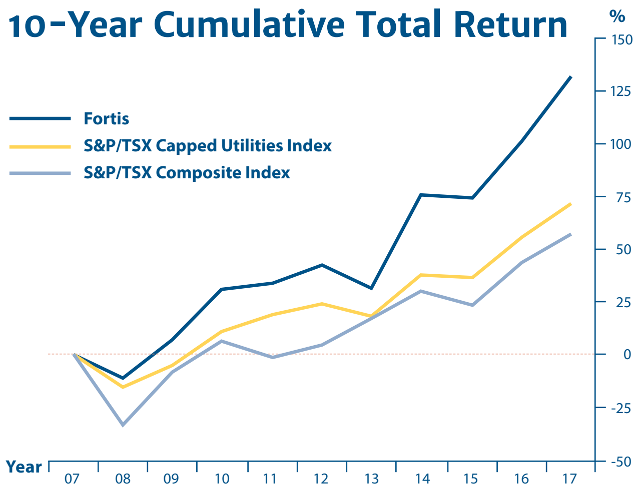
FORTIS *has more than* **DOUBLED** *its size in the last five years with the successful completion of three regulated utility acquisitions in the United States.*

2017 marked **44 CONSECUTIVE YEARS** *of annual common share dividend payment increases — one of the longest records for a Canadian public corporation.*

Strong Track Record of Total Shareholder Return

The 10-year cumulative total return of 132% for the period ended December 31, 2017 is approximately 60% and 74% higher than the performance of the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, respectively.

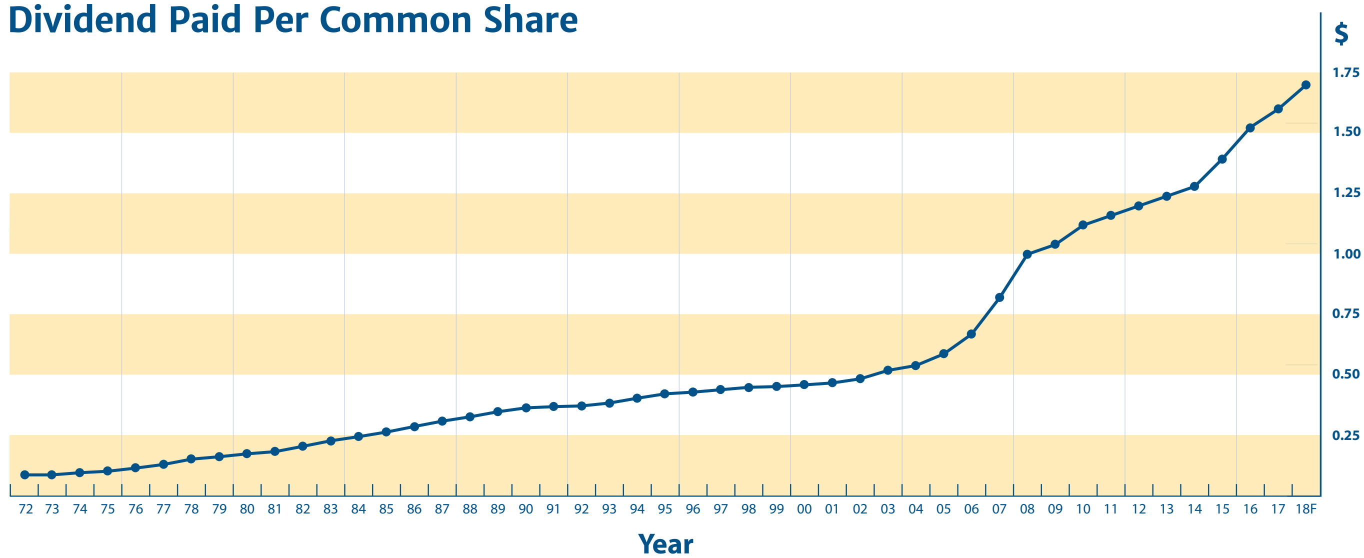
10-Year Cumulative Total Return



Achieved Average Annualized Total Shareholder Return of 8.8% Over the Last 10 Years

Fortis has extended its guidance for targeted average annual dividend per common share growth of 6% through 2022.

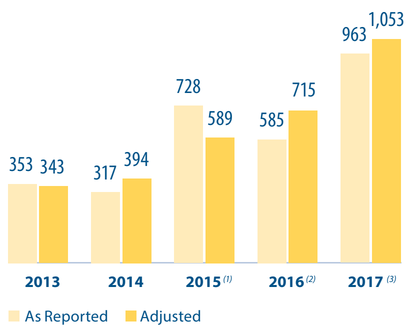
Dividend Paid Per Common Share



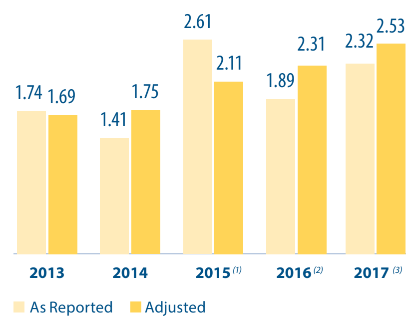
Financial Highlights

Fortis established two main objectives for 2017: the successful integration of ITC and reaching a constructive settlement of our first rate case at Tucson Electric Power. Our strong financial performance in 2017 is a testament to the accomplishment of these objectives.

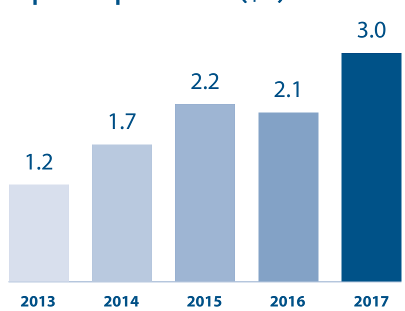
Net Earnings Attributable to Common Equity Shareholders ($M)



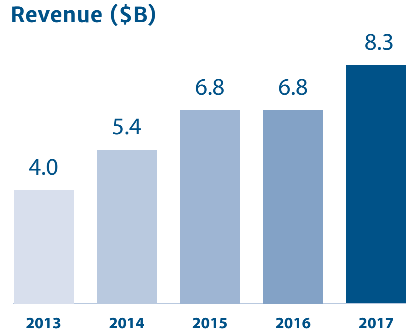
Basic Earnings per Common Share ($)



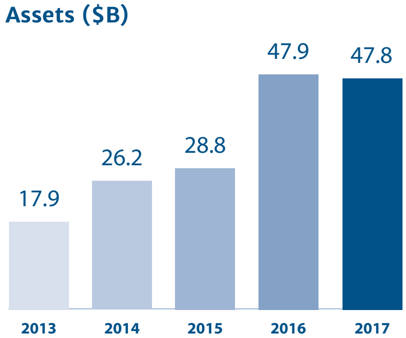
Capital Expenditures ($B)



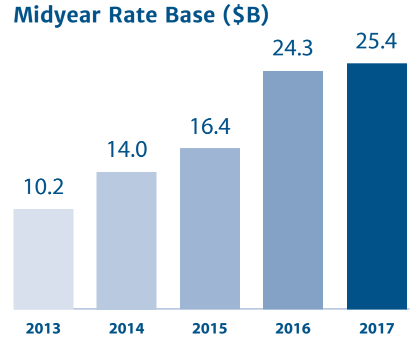
Revenue ($B)



Assets ($B)



Midyear Rate Base ($B)



(1) Results were impacted by a full year's contribution from UNS Energy, completion of the Waneta Expansion and gains on the sale of non-core assets. Adjusted net earnings exclude the gains on sale of non-core assets and other non-operating items.

(2) Results were impacted by accretion associated with the acquisition of ITC in October 2016 and Aitken Creek in April 2016, as well as associated acquisition-related costs. Adjusted net earnings exclude acquisition-related costs and other non-operating items.

(3) Results were impacted by a full year's contribution from ITC and Aitken Creek. Adjusted net earnings exclude the impact of U.S. Tax Reform and other non-operating items.

All financial information is presented in Canadian dollars.
Information is for the fiscal years ended December 31.

In 2017 **FORTIS** *reached over* **$1 BILLION** *in adjusted net earnings, a first in our history.*

Success of the Fortis Strategy Drives 2017 Growth

Doubling Our Size with Five Years of Incredible Growth in the United States

Fortis has more than doubled its size in the last five years with the successful completion of three regulated utility acquisitions in the United States. As a result of this push into the U.S. market, 60% of our business is now in the United States, elevating Fortis from a Canadian-focused utility business to a North American leader.

Fortis is one of the top 15 investor-owned utilities in North America when ranked by enterprise value. We are geographically diversified and highly regulated, making us one of the lowest-risk utility businesses in North America.

Our performance in 2017 was highlighted by the successful integration of ITC Holdings Corp. ("ITC"), the largest acquisition in the history of Fortis. The acquisition of ITC was accretive to our earnings per common share in 2017. With the integration of ITC complete, Fortis is well positioned to pursue growth in electricity transmission in North America.

Consistently Strong, Low-Risk Shareholder Return

Our unprecedented growth has increased our adjusted earnings per common share by an annual average of 8% for the last five years. This was driven by 24% rate base growth over the same period. Adjusted net earnings exceeded $1 billion in 2017 for the first time, and adjusted earnings per common share climbed by 10% over the previous year.

2017 marked 44 consecutive years of annual common share dividend payment increases. We also extended our guidance for targeted average annual dividend per common share growth of 6% through 2022. For the last ten years, on average, we have delivered 8.8% annualized total shareholder return.

Increased Focus on Cybersecurity and Sustainability

In 2017 we increased our focus on cybersecurity with the appointment of Phonse Delaney as our Executive Vice President, Chief Information Officer, and broadened Nora Duke's role to include matters related to sustainability when she was appointed Executive Vice President, Sustainability and Chief Human Resource Officer. These appointments elevated the responsibility for cybersecurity and sustainability to the executive level and demonstrate our commitment to these areas.

The Strength of Fortis in Response to Hurricane Irma

The strength of the Fortis operating model was on full display in September 2017 after Hurricane Irma struck the Turks and Caicos Islands. FortisTCI provides electricity to approximately 15,000 customers and operates 600 kilometres of power lines on the Turks and Caicos Islands.

The impact of Hurricane Irma on the Islands was significant and a quick response to restore power was critical to support Turks and Caicos, particularly given its tourism sector. The emergency response team included approximately 250 employees and contract personnel from all Fortis utilities who worked safely and efficiently to restore power to the country in less than 60 days. The restoration team rebuilt and restored many kilometres of transmission, distribution and service lines and replaced approximately 1,500 utility poles. The quick response was a testament to the strength and expertise of Fortis operations personnel and our ability to act quickly. Our response to the devastation caused by Hurricane Irma was one of our proudest achievements in 2017.

Investing in Our Networks: A Solid Platform to Grow Organically

After our strategic and successful expansion into the United States through key acquisitions, Fortis is focused on organic growth within our portfolio of utilities.

Our substantially autonomous business model positions us for success. Fortis utilities have the decision-making authority to run their businesses in the best interests of customers, while working closely with their respective regulators. We are able to leverage the quality of our assets, our operating expertise and the geographic footprint of our utilities to invest in our energy networks, to drive growth opportunities and to continue to deliver superior shareholder value.

Report to Shareholders

A Record Year of Financial Performance

2017 marked a strong year of financial performance for Fortis. We reached over $1 billion in adjusted net earnings[(1)], a first in the history of Fortis. Our results were driven largely by the success of our strategic push into the United States, which more than doubled the size of our business in the last five years.

We achieved adjusted net earnings of $1,053 million, or $2.53 per common share, in 2017 compared to $715 million, or $2.31 per common share, in 2016. Net earnings attributable to common equity shareholders for 2017 were $963 million, or $2.32 per common share, compared to $585 million, or $1.89 per common share, for 2016. The most significant adjustment to net earnings was to exclude the one-time non-cash charge to income tax expense related to the recently enacted tax legislation in the United States.

Fortis established two main objectives for 2017: the successful integration of ITC and reaching a constructive settlement of our first rate case at Tucson Electric Power ("TEP"). Our strong financial performance in 2017 is a testament to the accomplishment of these objectives.

The reasonable rate case settlement at TEP marked the first decision received since Fortis acquired the utility. Constructive regulatory outcomes provide stability for the Corporation's utilities and value for our customers, while building on our history of constructive regulatory relationships.

44 Consecutive Years of Annual Dividend Payment Increases

Fortis continued to deliver value to shareholders in 2017. We raised our fourth quarter 2017 dividend by 6.25%, translating into an annualized dividend of $1.70 per common share and a one-year total shareholder return of 15.3%. For the last five years, our adjusted earnings per share has grown by an annual average of 8%, one of the highest in the industry.

Over the past ten years, Fortis has delivered a 5.2% compound annual growth rate on earnings per share to shareholders, and an annual average total shareholder return of 8.8%. The increase in our dividend from $0.40 to $0.425 per common share in the fourth quarter of 2017 marks 44 consecutive years of annual dividend payment increases – one of the longest records for a Canadian public corporation.

(1) Non-U.S. GAAP Measure

Investing in Our Energy Networks: A Strong Five-Year Capital Expenditure Plan

During 2017 we announced a five-year capital expenditure plan of approximately $14.5 billion for the period 2018 to 2022, including approximately $3.2 billion to be invested in 2018. This plan is focusing on investment in our energy networks including projects that improve the transmission grid; automate the distribution grid; address natural gas system capacity and gas line network integrity; add natural gas resources to support solar energy expansion; and replace aging infrastructure. We remain focused on sustainable investment in our utilities to address the needs of our customers.

In 2017 our midyear rate base was $25.4 billion, an increase of $1.1 billion over 2016. Over the last five years, our rate base has grown by 24%. With the capital expenditure plan we have in place, our consolidated rate base is expected to climb to $32.4 billion by 2022. Changing customer expectations are driving our investment decisions as we aim to provide cleaner energy, as well as better communication and greater control over energy use, to customers.

Our base capital expenditure plan of $14.5 billion supports our ability to grow earnings, and we extended our targeted average annual dividend per common share growth of 6% through 2022.

Fortis Celebrates 30 Years of Trading on the Toronto Stock Exchange

Fortis began trading on the Toronto Stock Exchange on December 29, 1987, becoming the parent company of Newfoundland Light and Power Co. Limited, known today as Newfoundland Power. The vision was to identify and execute on new and emerging growth opportunities.

Since 1987 our assets have grown from $390 million to approximately $48 billion today, marking three decades of incredible growth. Newfoundland Power, which once represented 100% of our assets, now represents 3%. In terms of shareholder value, if a shareholder purchased 1,000 Fortis common shares in 1987 at a cost of $4,690, and held them through the end of 2017, including reinvestment of dividends, those shares would be worth more than $180,000 at December 31, 2017.

Fortis was founded 30 years ago with aspirations grounded in the strength of tradition, sound management, commitment and service. These goals and values remain at our core, and we have no doubt that our founders would be proud of Fortis today.

With **SAFETY** *being our #1 priority at all times, we empower our 8,500 employees to always make safe decisions for themselves and our 3.2 million customers.*

Increasing Our Sustainability Focus

In 2017 there were a number of significant advances as we increased our focus on sustainability for the benefit of the environment and our customers. Delivering cleaner energy is a key strategic initiative for Fortis as we plan for the future. Sustainability is also important to investors and is increasingly becoming a key focus of discussion during investor meetings.

Key sustainability developments included the release of two environmental reports in 2017 to provide current environmental data, and the appointment of executive-level responsibility for our environmental, social and governance commitments. Ms. Nora Duke assumed duties for matters related to sustainability and was appointed Executive Vice President, Sustainability and Chief Human Resource Officer. In this expanded role, she will focus on enterprise-wide sustainability and stewardship priorities.

Delivering Cleaner Energy to Customers

The safe transmission and distribution of energy is central to our business and constitutes 92% of our total assets. The remaining 8% is generation assets (5% fossil fuel-based and 3% renewables). Our largest utility in Arizona, TEP, is the primary producer of fossil fuel-based generation, and is taking significant steps to reduce coal-fired generation and resulting carbon emissions. TEP plans a 36% (508 megawatt) reduction in coal-fired generation over the next five years through plant retirements. The utility is also focused on renewable energy sources with planned solar and wind energy purchases that will give TEP a renewable portfolio that produces enough clean energy annually to serve the electricity needs of nearly one out of every three Tucson homes.

FortisOntario is partnering with First Nations communities in remote northwestern Ontario to connect these communities to the electricity grid for the first time. This development project, called the Wataynikaneyap Power Project, will enable communities to move away from a diesel plant system that produces significant greenhouse gas emissions, while providing greater reliability to meet the needs of residents.

Because much of the energy passing through our transmission and distribution system is not generated by Fortis, our focus is on how to facilitate bringing more renewable energy onto the grid while maintaining a strong, reliable system.

Increased Communication and Engagement with Shareholders

A board-shareholder engagement policy has been adopted to facilitate communication and engagement with shareholders on topics such as governance and executive compensation practices. In 2017 an inaugural board-shareholder engagement meeting was hosted by the Chair of the Board and two Committee Chairs. The meeting was attended by 11 of our largest shareholders, representing approximately 14% of our total shares outstanding, to proactively discuss our environmental, social and governance practices, and executive compensation.

Fortis Receives 2017 Governance Gavel Award

Fortis received the 2017 Governance Gavel Award from the Canadian Coalition for Good Governance for "best disclosure of corporate governance and executive compensation practices." The Governance Gavel Awards recognize excellence in shareholder communications by corporations through their annual proxy circulars. Fortis is a strong advocate for good governance and we continue to advance our communications and practices in this area.

The Fortis Energy Exchange is Launched

Fortis, in partnership with the Canadian Electricity Association, hosted The Fortis Energy Exchange in June 2017. The first of its kind, The Fortis Energy Exchange is a North American energy executive thought leadership forum designed to foster dialogue on the most important issues facing the utility sector. North America's most senior leaders in the electricity and gas sector discussed clean energy, technology and security, cross-jurisdictional energy transportation, integrated resource management, and a vision for the future of the electricity utility sector.

Executive Team Changes

David G. Hutchens was appointed Executive Vice President, Western Utility Operations, effective January 1, 2018. In this expanded role, Mr. Hutchens will continue as President and CEO of UNS Energy while also providing oversight to FortisBC and FortisAlberta operations. James R. Reid was appointed Executive Vice President, Chief Legal Officer and Corporate Secretary, effective March 5, 2018. Mr. Reid was previously a partner with Davies Ward Phillips & Vineberg LLP in Toronto, where he practiced for 20 years.

We increased our focus on cybersecurity with the appointment of Phonse Delaney as Executive Vice President, Chief Information Officer, effective June 1, 2017. Mr. Delaney has responsibility for our corporate technology strategy, including cybersecurity. He will keep us informed of technology trends and position Fortis to avail of and optimize technology opportunities through active collaboration with our subsidiaries. He will also provide oversight to our Fortis cybersecurity management. Mr. Delaney was previously President and CEO of FortisAlberta.

In 2017 Earl A. Ludlow, Executive Vice President, Operational Advisor, announced his retirement effective December 31, 2017. We recognize the contributions of Mr. Ludlow during his nearly 40 years with Fortis. There are few who have been as highly regarded in the North American utility sector as him. We thank Mr. Ludlow for his unwavering commitment to our corporation and wish him all the best in his future endeavours.

Gary J. Smith was appointed Executive Vice President, Eastern Canadian and Caribbean Operations, effective June 1, 2017. Mr. Smith succeeds Earl Ludlow and oversees our investments in Newfoundland Power, Maritime Electric, FortisOntario, FortisTCI, Caribbean Utilities and Belize Electric Company Ltd., and provides operational support across the organization. Mr. Smith was previously President and CEO of Newfoundland Power. He, along with Eddinton Powell, FortisTCI's President and CEO, led our successful response to the devastation caused by Hurricane Irma on the Turks and Caicos Islands. Our emergency response efforts on the Islands were perhaps our proudest accomplishment in 2017.

Election of Directors

Two new members, Lawrence T. Borgard and Joseph L. Welch, were welcomed to the Board, both bringing extensive experience in the U.S. energy sector. Mr. Borgard is a former President and Chief Operating Officer of Integrys Energy Group, a diversified energy holding company. Mr. Welch is the Chair of ITC's Board and also served as its President and Chief Executive Officer prior to its acquisition by Fortis.

We also wish to acknowledge the contribution and dedicated service of long-standing Board members Peter Case and David Norris. Both Mr. Case and Mr. Norris joined the Board in 2005, and after remarkable contributions retired from the Board in accordance with the terms of our Director Tenure Policy. We thank them for their service and outstanding leadership.

Recognizing the late Dr. Angus Bruneau and Michael Mulcahy

We were deeply saddened in 2017 by the passing of our founder, Dr. Angus Bruneau, and President and CEO of FortisBC, Michael Mulcahy.

Dr. Bruneau was the founding CEO of Fortis and guided the Corporation for nearly two decades as President and CEO and, following that, as Chair of the Board of Directors. His vision, unwavering perseverance and intellect laid the foundation of our success. He was a true gentleman whose courage, honesty and humility brought out the best in those around him. His values and leadership will live on at Fortis. In 2017 Fortis made a $200,000 donation to the Faculty of Engineering at Memorial University to modernize The Fortis Angus Bruneau Lecture Theatre in Dr. Bruneau's memory.

Fortis lost one of its best with the passing of Michael Mulcahy. Mr. Mulcahy was a long-time leader in the Fortis group of companies. Having served for a quarter of a century at Maritime Electric, Fortis Properties, Newfoundland Power and FortisBC, his steadfast approach and business acumen served us well. An advocate of positive corporate culture and strong talent, many knew him to be a trusted friend and advisor. Dr. Bruneau and Mr. Mulcahy will be dearly missed.

Community Involvement at Fortis

The Fortis group of companies and our employees have a proud history of supporting the communities we serve. In 2017 we invested millions of dollars and many volunteer hours in the communities in which we work and live throughout North America. Throughout the U.S. Midwest, ITC alone committed US$1.6 million in 2017 to more than 100 organizations across its seven-state footprint.

At our headquarters location, Fortis made the largest corporate donation ever to The Salvation Army – Newfoundland and Labrador Division in 2017 with a $1,000,000 contribution to The Salvation Army's Centre of Hope ("the Centre") in St. John's, NL. The Centre will be a neighbour of Fortis and will provide housing for the homeless, a health clinic, a food bank, emergency disaster services, mental health services and drug addiction programs for those most vulnerable in our society.

Douglas Haughey,
Chair of the Board, Fortis Inc.

Barry Perry,
President and CEO, Fortis Inc.

In 2017 Fortis launched a new community initiative called *Tap Your Potential* in its home province of Newfoundland and Labrador. *Tap Your Potential* profiles homegrown achievers in every field, sharing inspiring stories and insights that show Newfoundlanders and Labradorians just how much is possible. Our Fortis team also shares career advice and stories of their own success. To learn more visit www.tapyourpotential.ca.

Fortis and our utilities joined together to announce a US$100,000 contribution to the American Red Cross Hurricane Harvey response. The donation provided funding for relief efforts and residents impacted by Hurricane Harvey. The contribution was made by Fortis in partnership with our utilities Central Hudson (New York), ITC (Michigan) and UNS Energy (Arizona).

Looking Forward

After our successful expansion into the United States, Fortis is focused on organic growth at our utility businesses in 2018. The locations, varying sizes and operating expertise of our utilities create opportunities to drive growth for the future. The quality and diversity of our utilities make Fortis one of the lowest-risk utility businesses in North America.

Over the long term, Fortis is well positioned to enhance value for shareholders through the execution of its capital plan, the balance and strength of its portfolio of businesses, as well as growth opportunities within its service territories. Finally, we express our sincerest appreciation to our Board of Directors for their continued guidance and leadership.

On behalf of the Board of Directors,

Douglas J. Haughey
Chair of the Board
Fortis Inc.

Barry V. Perry
President and CEO
Fortis Inc.

Management Discussion and Analysis

Contents

Dated February 14, 2018

FORWARD-LOOKING INFORMATION

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. This MD&A should be read in conjunction with the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2017. Financial information for 2017 and comparative periods contained in this MD&A has been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, collectively referred to as "forward-looking information". Forward-looking information included in the MD&A reflect expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which include, without limitation: the expectation that the Corporation will remain at the forefront of emerging technologies; the Corporation's forecast gross consolidated and segmented capital expenditures for 2018 and for the period 2018 through 2022 and expected associated increase to rate base; expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to long-term capital in 2018; targeted average annual dividend growth through 2022; expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; statements related to Fortis Turks and Caicos' recovery of lost revenue as a result of the impact of Hurricane Irma and the timing thereof; the nature, timing, funding sources and expected costs of certain capital projects including, without limitation, the ITC Multi-Value Regional Transmission Projects and 34.6 to 69 kV Conversion Project, UNS Energy flexible generation resource investment and Gila River Generating Station Unit 2, FortisBC Energy expansion of the Tilbury liquefied natural gas ("LNG") facility, Eagle Mountain Woodfibre Gas Pipeline Project, Lower Mainland System Upgrade and Pipeline Integrity Management Program and additional opportunities beyond the base plan including the Wataynikaneyap Project, the Lake Erie Connector Project and additional LNG infrastructure investment in British Columbia; the expectation that subsidiary operating expenses and interest costs will be paid out of subsidiary operating cash flows; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from Fortis; the expectation that maintaining the targeted capital structure of the Corporation's regulated operating subsidiaries will not have an impact on its ability to pay dividends in the foreseeable future; the expectation that cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions will be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from *the issuance of common shares, preference shares and long-term debt; expected consolidated fixed-term debt maturities and repayments in 2018 and over the next five years; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout 2018; statements related to the at-the-market program including but not limited to the timing, receipt of regulatory approvals and the entering into agreements with agents; the intent of management to refinance certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities with long-term permanent financing; the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements; the impact of U.S. Tax Reform on the Corporation's annual earnings per share and cash flows at the Corporation's U.S. regulated utilities and rate base growth; and the expectation that long-term sustainable growth in rate base will support continuing growth in earnings and dividends.*

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

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

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

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CORPORATE OVERVIEW

Karl Smith, EVP, CFO, Fortis Inc.

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

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's utilities are primarily determined under cost of service ("COS") regulation, in combination with performance-based rate-setting ("PBR") mechanisms in certain jurisdictions. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

Earnings of regulated utilities may be impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and common equity component of capital structure; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates, as applicable; (vi) regulatory lag in the case of a historical test year; and (vii) foreign exchange rates. The Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Fortis segments its business based on regulatory status and service territory, as well as the information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of the segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, and assumes responsibility for net earnings and its own resource allocation.

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

Regulated Utilities – United States

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

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

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

UNS Energy's largest operating subsidiary, TEP, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 422,000 retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States. UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to approximately 96,000 retail customers in Arizona's Mohave and Santa Cruz counties. TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,834 MW, including 64 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2017, approximately 44% of the generating capacity was fuelled by coal.

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

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

Regulated Utilities – Canada

a. *FortisBC Energy:* FortisBC Energy Inc. ("FortisBC Energy") is the largest regulated distributor of natural gas in British Columbia, serving approximately 1,008,000 customers in more than 135 communities. FortisBC Energy provides transmission and distribution services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FortisBC Energy's Southern Crossing pipeline, from Alberta.

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

c. *FortisBC Electric:* Includes FortisBC Inc. ("FortisBC Electric"), an integrated regulated electric utility operating in the southern interior of British Columbia, serving approximately 172,000 customers directly and indirectly. FortisBC Electric owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia primarily owned by third parties, one of which is the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT").

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

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

Regulated Utilities – Caribbean

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

Non-Regulated

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

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

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

CORPORATE STRATEGY

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

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

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

KEY TRENDS, RISKS AND OPPORTUNITIES

Energy Industry Developments: The North American energy industry continues to transform. There is a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. Notwithstanding the changes occurring in the utility industry, safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of the utility industry's focus.

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

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

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

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

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

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

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

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

All of the Corporation's regulated utilities continue to be actively engaged with each of their regulators and are focused on maintaining constructive regulatory relationships and outcomes. For a further discussion of material regulatory decisions and applications and regulatory risk, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth: The Corporation's regulated midyear rate base for 2017 was $25.4 billion. Over the five-year period through 2022, the Corporation's capital expenditure program is expected to be approximately $14.5 billion. This investment in energy infrastructure is expected to increase rate base to over $32 billion by 2022 and produce a five-year compound annual growth rate in rate base of approximately 5%. The three-year compound annual growth rate in rate base through 2020 is expected to be approximately 6%, reflecting greater visibility in capital expenditures in the first three years of the capital expenditure program. Fortis expects this capital investment to support growth in earnings and dividends.

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

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities usually issue debt at terms ranging between 5 and 40 years. As at December 31, 2017, approximately 80% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately $650 million annually over the next five years.

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

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

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

SIGNIFICANT ITEM

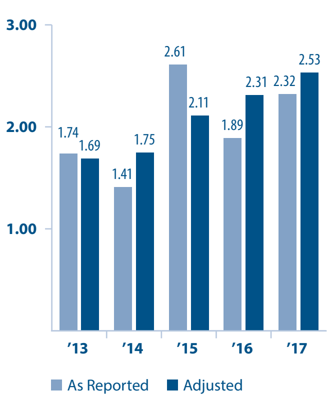
U.S. Tax Reform: On December 22, 2017, the *Tax Cuts and Jobs Act* was signed into law by the President of the United States of America, enacting significant changes to tax legislation ("U.S. Tax Reform"). The changes included a reduction in the federal corporate income tax rate from 35% to 21% effective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

SUMMARY FINANCIAL HIGHLIGHTS

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

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

Basic Earnings per Common Share
($)



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

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

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

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

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

Capital Expenditures: Consolidated capital expenditures were $3.0 billion in 2017 compared to $2.1 billion in 2016. Consolidated capital expenditures for 2017 were consistent with the Corporation's 2017 forecast of $3.0 billion, as disclosed in the MD&A for the year ended December 31, 2016. The increase in capital expenditures from 2016 was driven by capital spending at ITC and higher capital spending at most of the Corporation's regulated utilities. For a detailed discussion of the Corporation's consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

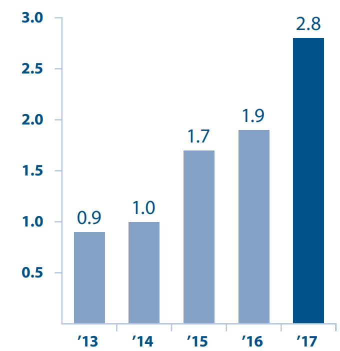
Long-Term Capital: The Corporation's regulated utilities raised approximately $2.5 billion in long-term debt in 2017, largely in support of energy infrastructure investment and regularly scheduled debt repayments.

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

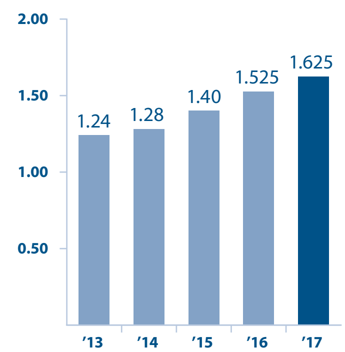
In March 2017 approximately 12.2 million common shares of Fortis were issued to an institutional investor for proceeds of $500 million. The proceeds were used to repay short-term borrowings.

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

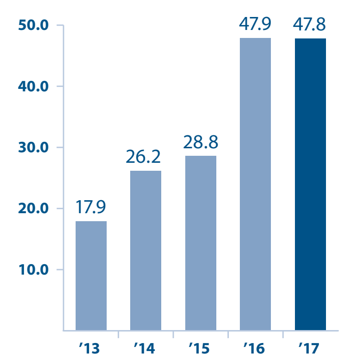
Cash Flow from Operating Activities
($ billions)



Dividends Paid per Common Share
($)



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



CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31

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

Revenue

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

Energy Supply Costs

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

Operating Expenses

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

Depreciation and Amortization

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

Other Income, Net

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

Finance Charges

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

Income Tax Expense

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

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

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

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

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

Fortis uses financial measures, being adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share, that do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. Therefore, these adjusting items may not be comparable with similar adjustments presented by other companies. The most directly comparable US GAAP measures to adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share are net earnings attributable to common equity shareholders and basic earnings per common share, respectively.

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

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

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

Non-US GAAP Reconciliation

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

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

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

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

REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2017 earnings from regulated utilities represented approximately 92% (2016 – 93%) of the Corporation's earnings from its operating segments, excluding Corporate and Other segment expenses. Total regulated utility assets represented approximately 97% of the Corporation's total assets as at December 31, 2017 (December 31, 2016 – 97%).

Regulated Utilities – United States

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

ITC

Financial Highlights [1]

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

(1) Revenue represents 100% of ITC, while earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflects consolidated purchase price accounting adjustments.

(2) The reporting currency of ITC is the US dollar. The average US:CAD exchange rate for 2016 is from October 14, 2016, the date of acquisition.

Revenue and Earnings

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

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

UNS Energy

Financial Highlights

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

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

Electricity Sales & Gas Volumes

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

Gas volumes were comparable with 2016.

Revenue

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

Earnings

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

Central Hudson

Financial Highlights

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

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

Electricity Sales & Gas Volumes

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

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

Revenue

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

Earnings

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

Regulated Utilities – Canada

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

FortisBC Energy

Financial Highlights

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

Gas Volumes

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

Revenue

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

Earnings

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

FortisBC Energy earns approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulatory deferral mechanisms, changes in consumption levels and the cost of natural gas do not materially affect earnings.

FortisAlberta

Financial Highlights

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

Energy Deliveries

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

Revenue

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

Earnings

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

FortisBC Electric

Financial Highlights

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

Electricity Sales

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

Revenue

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

Earnings

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

Eastern Canadian

Financial Highlights

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

Electricity Sales

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

Revenue

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

Earnings

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

Regulated Utilities – Caribbean

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

Financial Highlights

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

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

Electricity Sales

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

Revenue

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

Earnings

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

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

NON-REGULATED

Energy Infrastructure

Financial Highlights

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

Energy Sales

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

Revenue and Earnings

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

Corporate and Other

Financial Highlights

Years Ended December 31

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

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

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

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

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

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

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

REGULATORY HIGHLIGHTS

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

ITC

ROE Complaints

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

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

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

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

UNS Energy

General Rate Application

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

FERC Order

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

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

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

Central Hudson

General Rate Application

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

FortisAlberta

Generic Cost of Capital

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

Next Generation Performance-Based Rate-Setting Proceeding

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

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

Significant Regulatory Proceedings

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

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

CONSOLIDATED FINANCIAL POSITION

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

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

Summary of Consolidated Cash Flows

Years Ended December 31

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

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

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

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

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

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

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

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

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2017**	2016	Variance
ITC [(1)]	**1,863**	264	1,599
Central Hudson [(2)]	**74**	68	6
FortisBC Energy [(3)]	**173**	446	(273)
FortisAlberta [(4)]	**199**	149	50
FortisBC Electric [(5)]	**74**	–	74
Eastern Canadian [(6) (7)]	**75**	40	35
Caribbean [(8) (9)]	**80**	65	15
Corporate [(10)]	**–**	3,104	(3,104)
Total	**2,538**	4,136	(1,598)

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

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

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

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

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

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

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

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

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

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

Borrowings under credit facilities by the utilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility.

Common share dividends paid in 2017 totalled $419 million, net of $253 million of dividends reinvested, compared to $316 million, net of $162 million of dividends reinvested, paid in 2016. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.625 in 2017 compared to $1.525 in 2016. The weighted average number of common shares outstanding was 415.5 million for 2017 compared to 308.9 million for 2016.

Contractual Obligations

The Corporation's consolidated contractual obligations with external third parties in each of the next five years and for periods thereafter, as at December 31, 2017, are outlined in the following table.

Contractual Obligations

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

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

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

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

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

FortisBC Electric: Power purchase obligations for FortisBC Electric, totalling $333 million as at December 31, 2017, include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term. FortisBC Electric is also party to the Waneta Expansion Capacity Agreement ("WECA"), allowing it to purchase 234 MW of capacity per month, on average, for 40 years, effective April 2015, as approved by the British Columbia Utilities Commission ("BCUC"). Amounts associated with the WECA have not been included in the Contractual Obligations table as they will be paid by FortisBC Electric to a related party.

Maritime Electric: Maritime Electric's power purchase obligations include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power"). Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, and as at December 31, 2017, had commitments of $511 million under this arrangement.

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

(4) Certain of the Corporation's subsidiaries, mainly FortisBC Energy, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2017.

(5) UNS Energy enters into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts.

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

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

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

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

(10) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including Performance Share Unit, Restricted Share Unit and Directors' Deferred Share Unit plan obligations, land easements, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Contractual Obligations

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $3.2 billion for 2018. Over the five-year period from 2018 through 2022, the Corporation's consolidated capital expenditure program is expected to be approximately $14.5 billion, which has not been included in the Contractual Obligations table.

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

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

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

Capital Structure

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

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

Capital Structure

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

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

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

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

Credit Ratings

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

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

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the standalone nature and financial separation of each of the regulated subsidiaries of Fortis, and the level of debt at the holding company. In May 2017 S&P and DBRS affirmed the Corporation's long-term corporate and unsecured debt credit ratings, and in September 2017 Moody's affirmed the Corporation's long-term issuer and unsecured debt credit ratings.

Capital Expenditure Program

Capital investment in energy infrastructure is required to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $440 million in maintenance and repairs was expensed in 2017 compared to approximately $330 million in 2016. The increase was largely due to a full year of expense for ITC in 2017.

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

Consolidated Capital Expenditures [1]

Year Ended December 31, 2017

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

(1) Represents cash payments to construct property, plant and equipment and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC.
(2) Includes Energy Infrastructure and Corporate and Other segments
(3) Includes capital expenditures associated with the Tilbury LNG facility expansion at FortisBC Energy and Alberta Electric System Operator ("AESO") transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast. Consolidated capital expenditures of $3.0 billion for 2017 were consistent with the 2017 forecast of $3.0 billion, as disclosed in the MD&A for the year ended December 31, 2016.

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

Forecast Consolidated Capital Expenditures [1]

Year Ending December 31, 2018

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

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

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

Consolidated Capital Expenditures

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

[1] Capital expenditures to connect new customers and infrastructure upgrades required to meet customer and associated load growth, including capital expenditures associated with the Tilbury LNG facility expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

[2] Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation, transmission and distribution assets

[3] Relates to facilities, equipment, vehicles, information technology systems and other assets

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

The approximate breakdown of the capital spending expected to be incurred is as follows: 55% at U.S. Regulated Utilities, including 25% at ITC; 40% at Canadian Regulated Utilities; 4% at Caribbean Regulated Utilities; and the remaining 1% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 34% to meet customer growth, 53% for sustaining capital expenditures, and 13% for facilities, equipment, vehicles, information technology and other assets.

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

Midyear Rate Base

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

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

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

Significant Capital Projects[1]

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

(1) Represents property, plant and equipment and intangible asset expenditures, including both the capitalized debt and equity components of AFUDC, where applicable. Significant capital projects are identified as those with a total project cost of $150 million or greater and exclude ongoing capital maintenance projects.

(2) Capital expenditures prior to 2017 are from the date of acquisition of October 14, 2016.

(3) Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CAD$1.28 for 2018 through 2022.

(4) FortisBC Energy is currently in the process of reassessing costs following completion of detailed engineering work and evaluation of construction bids and other costs.

(5) Net of forecast customer contributions.

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

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

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

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

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

The Lower Mainland System Upgrade project at FortisBC Energy is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia. The project will be completed in two phases: (i) the Coastal Transmission System ("CTS") phase, which is intended to increase security of supply; and (ii) the Lower Mainland Intermediate Pressure System Upgrade ("LMIPSU") project phase, which is focused on addressing pipeline condition issues. Construction activities for the CTS project are complete, and the new pipelines have been commissioned and are in-service. FortisBC Energy is currently in the process of reassessing costs for the LMIPSU project phase following completion of detailed engineering work and evaluation of construction bids and other costs. The project is expected to be constructed during 2018 and 2019. The total capital cost of both phases of the Lower Mainland System Upgrade is estimated to be approximately $420 million, with approximately $177 million forecast to be spent in 2018. The BCUC approved the application to replace certain sections of intermediate pressure pipeline segments within the Greater Vancouver area in October 2015.

The Eagle Mountain Woodfibre Gas Pipeline Project at FortisBC Energy is a pipeline expansion at a proposed LNG site in Squamish, British Columbia. The current estimate of FortisBC Energy's investment in the project may be updated for final scoping, detailed construction estimates and scheduling, and final determination of customer capital contributions. FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting this project from further regulatory approval by the BCUC. Woodfibre LNG Limited has obtained an export licence from the National Energy Board ("NEB"), which was recently extended from 25 to 40 years, and received environmental assessment approvals from the Squamish First Nation, the British Columbia Environmental Assessment Office and the Canadian Environmental Assessment Agency. FortisBC Energy also received environmental assessment approval from the Squamish First Nation and provincial environmental assessment approval in 2016. In November 2016 Woodfibre LNG Limited announced the approval from its parent company, Pacific Oil & Gas Limited, which is part of the Singapore-based RGE group of companies, of the funds necessary to proceed with the project. Given the increased certainty with the number of project approvals received and the level of planning, engineering and expenditures completed by Woodfibre LNG Limited to date, the Eagle Mountain Woodfibre Gas Pipeline Project has been included in the five-year capital program. FortisBC Energy's anticipated capital expenditures, net of forecast customer contributions, is $350 million and remains contingent on Woodfibre LNG Limited making a final investment decision. Should the project proceed, it is not expected to be in service before 2021.

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

Additional Investment Opportunities

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

FortisOntario – Wataynikaneyap Power Project

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

ITC – Lake Erie Connector

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

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

FortisBC Energy – LNG

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

Other Opportunities

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

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flows available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from Fortis.

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

Cash required of Fortis to support subsidiary capital expenditure programs is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends.

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

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

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

As at December 31, 2017, management expects consolidated fixed-term debt maturities and repayments to be $394 million in 2018 and to average approximately $650 million annually over the next five years. The combination of available credit facilities, the US$400 million commercial paper program at ITC, and manageable annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management" section of this MD&A.

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

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

Credit Facilities

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

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

Credit Facilities

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

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

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

As at December 31, 2017 and 2016, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

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

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

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

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

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

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

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2022, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $40 million unsecured committed revolving credit facility, maturing in June 2020.

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

Corporate and Other

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

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

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $129 million as at December 31, 2017 (December 31, 2016 – $119 million), the Corporation had no off-balance sheet arrangements that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's principal risks that could materially affect its business, results of operations, financial condition or cash flows. Other risks may arise or risks not currently considered material may become material in the future.

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

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

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

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

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

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

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1 Operating revenue and operating earnings are non-US GAAP measures and refer to total revenue, excluding Corporate and Other segment revenue and inter-segment eliminations, and net earnings attributable to common equity shareholders, excluding Corporate and Other segment expenses, respectively. Operating revenue and operating earnings are measures used by the chief operating decision maker in evaluating the performance of the Corporation's operating subsidiaries.

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

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

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

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

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

The Corporation and its subsidiaries may also be exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and refinancing of long-term debt. At the utilities, interest expense is generally recovered in customer rates, as approved by the regulators. The inability to flow through interest costs to customers could have an adverse effect on the results of operations, financial condition and cash flows of the utilities. In addition, a change in the level of interest rates could affect the measurement and disclosure of the fair value of long-term debt.

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

The ongoing operation of the utilities' facilities involves risks customary to the electric and gas utility industry, including storms and severe weather conditions, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the utilities. Such occurrences could result in service disruptions and the inability to deliver electricity or gas to customers in an efficient manner, resulting in lower earnings and/or cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated cost recovery.

The operation of the Corporation's electric generating stations involves certain risks, including equipment breakdown or failure, interruption of fuel supply and lower-than-expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of the generation business. There can be no assurance that the generation facilities of Fortis will continue to operate in accordance with expectations.

The operation of electricity transmission and distribution assets is also subject to certain risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. Certain of the Corporation's utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature. In addition, a significant portion of the utilities' infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged.

The Corporation's gas utilities are exposed to various operational risks associated with gas, including fires, explosions, pipeline leaks, accidental damage to mains and service lines, corrosion in pipes, pipeline or equipment failure, other issues that can lead to outages and/or leaks, and any other accidents involving gas that could result in significant operational disruptions and/or environmental liability.

The Corporation and its subsidiaries have limited insurance that provides coverage for business interruption, liability and property damage. In the event of a large uninsured loss caused by severe weather conditions, natural disasters and certain other events beyond the control of the utility, an application would be made to the respective regulatory authority for the recovery of these costs through customer rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole, or in part. For further detail on the Corporation's insurance coverage, refer to the insurance coverage risk discussion within the "Business Risk Management" section of this MD&A.

The Corporation's electricity and gas systems require ongoing maintenance, improvement and replacement. The utilities could experience service disruptions and increased costs if they are unable to maintain their asset base. The inability to recover, through approved customer rates, the expenditures the utilities believe are necessary to maintain, improve, replace and remove assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Generally, the Corporation's utilities have designed their electricity and gas systems to service customers under various contingencies in accordance with good utility practice. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, processes and/or procedures to ensure the safety of employees and contractors, as well as the general public. Failure to do so may disrupt the ability of the utilities to safely generate, transmit and distribute electricity and gas, which could have an adverse effect on the operations of the utilities, as well as harm the reputation of the Corporation and the respective utility.

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

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

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

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

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

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

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

The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial condition of the Corporation and its subsidiaries, the regulatory environment in which the Corporation's utilities operate and the outcome of regulatory decisions regarding capital structure and allowed ROEs, conditions in the capital and bank credit markets, ratings assigned by credit rating agencies, and general economic conditions. Funds generated from operations after payment of expected expenses, including interest payments on any outstanding debt, may not be sufficient to fund the repayment of all outstanding liabilities when due or anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and repay existing debt.

Consolidated fixed-term debt maturities in 2018 are expected to total $394 million. The ability to meet long-term debt repayments when due will be dependent on the Corporation and its subsidiaries obtaining sufficient and cost-effective financing to replace maturing indebtedness. Activity in the global capital markets may impact the cost and timing of issuance of long-term debt by the Corporation and its subsidiaries. Although the Corporation and its subsidiaries have been successful at raising long-term capital at reasonable rates, the cost of raising capital could increase and there can be no assurance that the Corporation and its subsidiaries will continue to have reasonable access to capital in the future.

Generally, the Corporation and its utilities rated by credit rating agencies are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt and credit facilities. A change in credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities.

In 2017 the following changes occurred to the debt credit ratings of the Corporation's utilities. In April 2017 S&P upgraded TEP's unsecured debt rating to 'A–' from 'BBB+' and in September 2017 S&P upgraded ITC's unsecured debt rating to 'A–' from 'BBB+'. For details on the Corporation's credit ratings, see the "Credit Ratings" section of this MD&A.

Additional information on the Corporation's consolidated credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A.

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

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

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

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

As operators of critical energy infrastructure, the Corporation's utilities face a heightened risk of cyber-attacks. Information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business, customer and employee information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation, transmission and distribution facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

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

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

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

At the Corporation's gas utilities, weather has a significant impact on gas distribution volumes as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas consumption patterns, the gas utilities normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. The earnings associated with the Corporation's gas utilities are highest in the first and fourth quarters.

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

Despite preparations for severe weather, ice, wind and snow storms, hurricanes and other natural disasters, weather will always remain a risk to the physical assets of utilities. Climate change may have the effect of increasing the severity and frequency of weather-related natural disasters that could affect the Corporation's service territories. Although physical utility assets have been constructed and are operated and maintained to withstand severe weather, there can be no assurance that they will successfully do so in all circumstances.

Earnings from non-regulated generation assets in Belize and British Columbia are sensitive to rainfall levels and the related impact on water flows. Hydrologic risk associated with hydroelectric generation at the Waneta Expansion and FortisBC Electric is reduced by the Canal Plant Agreement, under which fixed energy and capacity entitlements will be received based upon long-term average water flows. Prolonged adverse weather conditions, however, could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the entitlement of the Waneta Expansion and FortisBC Electric to capacity and energy under the Canal Plant Agreement.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Government policy has also impacted the competitiveness of gas in British Columbia. The Government of British Columbia has introduced changes to energy policy, including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels. The Government of British Columbia has yet to introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes in energy policy may impact the competitiveness of gas relative to non-carbon-based or other energy sources.

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

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

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

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

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

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

Certain of the generating facilities from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities and, therefore, may not be able to ensure the proper management of the operations and maintenance of the generating facilities. Further, TEP may have no or limited ability to make determinations on how best to manage the changing economic conditions or environmental requirements that may affect such facilities. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business, results of operations, financial condition and cash flows.

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

The emergence of initiatives designed to reduce greenhouse gas emissions and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce power, enable more efficient storage of energy or reduce power consumption. New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to have a significant impact on retail sales, which could negatively impact the business, results of operations, financial condition and cash flows of the Corporation's utilities. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. The Corporation's utilities are promoting demand-side management programs designed to help customers reduce their energy usage. These technologies include energy derived from renewable energy sources, customer-owned generation, appliances, battery storage, equipment and control systems. Advances in these, or other technologies, could have a significant impact on retail sales, which could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities.

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

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

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

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

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

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

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

The Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their physical assets, for amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including practices of owners of similar assets and operations. However, a significant portion of the Corporation's regulated electric utilities' transmission and distribution assets are not covered under insurance, as is customary in North America, as the cost of coverage is not considered economically viable. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's utilities would likely apply to their respective regulatory authority to recover any loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole, or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs, loss of revenue and customer claims that are substantial in amount and could have an adverse effect on the Corporation's business, results of operations, financial position and cash flows. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or material damage that is self-insured, could have an adverse effect on the Corporation's business, results of operations, financial position and cash flows.

It is anticipated that insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable, that insurance will continue to be available on terms as favourable as the existing arrangements, or that the insurance companies will meet their obligations to pay claims.

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

The acquisition, ownership and operation of electric and gas utilities and assets require numerous licences, permits, agreements, orders, approvals and certificates from various levels of government, government agencies and/or third parties. For various reasons, including increased stakeholder participation, the Corporation's regulated utilities and non-regulated energy infrastructure operations may not be able to obtain or maintain all required approvals. If there is a delay in obtaining any required approvals, failure to obtain or maintain any required approvals, failure to comply with any applicable law, regulation or condition of an approval, or there is a material change to any required approval, the operation of the assets and the sale of electricity and gas could be prevented or become subject to additional costs, any of which could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation and its utilities.

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

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

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

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

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

The Corporation's utilities in British Columbia provide service to customers on First Nations' lands and maintain gas facilities and electric generation, transmission and distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the Corporation's service territories is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to structure settlements without prejudicing existing rights held by third parties. However, there can be no certainty that the settlement process will not have an adverse effect on the results of operations, financial condition and cash flows of the Corporation's utilities in British Columbia.

The Corporation has distribution assets on First Nations' lands in Alberta with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual First Nations band councils must grant approval. FortisAlberta may be unable to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have an adverse effect on FortisAlberta.

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

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

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

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

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

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

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

CHANGES IN ACCOUNTING POLICIES

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

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

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

FUTURE ACCOUNTING PRONOUNCEMENTS

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

Revenue from Contracts with Customers: ASU No. 2014-09 was issued in May 2014 and the amendments in this update, along with additional ASUs issued in 2016 and 2017 to clarify implementation guidance, create Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard clarifies the principles for recognizing revenue and enables users of financial statements to better understand and consistently analyze an entity's revenues across industries and transactions. The new guidance permits two methods of adoption: (i) the full retrospective method; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption supplemented by additional disclosures. This standard is effective for annual and interim periods beginning after December 15, 2017. Fortis adopted this ASU on January 1, 2018 using the modified retrospective approach and there have been no material adjustments identified to opening retained earnings.

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

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

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

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

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

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

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

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

FINANCIAL INSTRUMENTS

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

Financial Instruments

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

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

The following tables present, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

Financial Instruments Carried at Fair Value

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

Financial Instruments Carried at Fair Value

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

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

(2) Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

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

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

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

Derivative Instruments

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

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

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

FortisBC Energy holds gas supply contracts and fixed-price financial swaps to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on published market prices and forward curves for natural gas.

These energy contracts were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recognized in earnings. As at December 31, 2017, unrealized losses of $87 million (December 31, 2016 – $19 million) were recognized in regulatory assets and unrealized gains of $2 million were recognized in regulatory liabilities (December 31, 2016 – $12 million).

Energy Contracts Not Subject to Regulatory Deferral

UNS Energy holds wholesale trading contracts that qualify as derivative instruments to fix power prices and realize potential margin, of which 10% of any realized gains are shared with customers through UNS Energy's rate stabilization accounts. The fair value of the wholesale contracts was measured using a market approach using independent third-party information, where possible.

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

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

Foreign Exchange Contracts

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

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

Interest Rate and Total Return Swaps

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

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

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

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

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

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

Other Investments

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

Volume of Derivative Activity

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

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

[1] GWh means gigawatt hours and PJ means petajoules.

CRITICAL ACCOUNTING ESTIMATES

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

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and liabilities arise as a result of the rate-setting process at the regulated utilities and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

As at December 31, 2017, Fortis recognized a total of \$3.0 billion in regulatory assets (December 31, 2016 – \$2.9 billion) and \$3.4 billion in regulatory liabilities (December 31, 2016 – \$2.2 billion). The increase in regulatory liabilities was primarily due to the impact of U.S. Tax Reform, reflecting the reduction in deferred income tax expense expected to be refunded to customers. For further discussion of the nature of regulatory decisions, refer to the "Regulatory Highlights" section of this MD&A.

Depreciation and Amortization: Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2017, the Corporation's consolidated property, plant and equipment and intangible assets were approximately \$30.7 billion, or approximately 64% of total consolidated assets (December 31, 2016 – \$30.3 billion, or approximately 63% of total consolidated assets). Depreciation and amortization was \$1,179 million for 2017 (2016 – \$983 million).

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

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

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

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

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

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

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

For those reporting units where: (i) management's assessment of qualitative and quantitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year.

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

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

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

Employee Future Benefits:

Defined Benefit Pension Plans

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

The expected weighted average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2018, is 5.78%, which is down from 5.97% used for 2017. The decrease in the average long-term rate of return reflects lower expected returns from fixed income and equity investments. The defined benefit pension plan assets experienced total positive returns of approximately $336 million in 2017 compared to expected positive returns of $151 million. The expected long-term rates of return on pension plan assets are developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio re-balancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2017, and to determine net pension cost for 2018, is 3.58%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2016, and to determine net pension cost for 2017, of 4.00%. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year.

Consolidated defined benefit pension costs were comparable with 2016. Higher expected return on plan assets, lower amortization of actuarial losses and lower regulatory adjustments for 2017 compared to 2016, were largely offset by higher service and interest costs related to the acquisition of ITC. Any increases or decreases in defined benefit net pension cost at the regulated utilities for 2018 are expected to be recovered from or refunded to customers in rates, subject to regulatory lag and forecast risk at certain of the utilities.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2017 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2017 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2017

(Decrease) increase *($ millions)*	**Net pension benefit cost**	**Projected benefit obligation** [(1)]
Impact of increasing the rate of return assumption by 100 basis points	(25)	21
Impact of decreasing the rate of return assumption by 100 basis points	21	(59)
Impact of increasing the discount rate assumption by 100 basis points	(33)	(422)
Impact of decreasing the discount rate assumption by 100 basis points	50	538

(1) At FortisBC Energy and FortisBC Electric certain defined benefit pension plans have pension indexing provisions that provide for a portion of investment returns to be allocated in order to provide for indexing of pension benefits. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation.

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

At FortisAlberta, as approved by the regulator, the cost of defined benefit pension plans is recovered in customer rates based on the cash payments made with any difference between the cash payments made and the cost incurred being deferred as a regulatory asset or regulatory liability. ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net pension cost from forecast net pension cost used to set customer rates. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2017, for defined benefit pension plans, the Corporation had consolidated projected benefit obligations of $3.2 billion (December 31, 2016 – $3.0 billion) and consolidated plan assets of $2.8 billion (December 31, 2016 – $2.6 billion), for a consolidated funded status in a liability position of $0.4 billion (December 31, 2016 – $0.4 billion). In 2017 the Corporation recognized consolidated net pension benefit cost of $87 million (2016 – $88 million).

OPEB Plans

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and the accumulated benefit obligation. Similar assumptions as described above, along with the health care cost trend rate, were also used by management in determining net benefit OPEB cost and accumulated benefit obligation.

The OPEB plan assets at ITC, UNS Energy and Central Hudson experienced positive returns of $37 million in 2017 compared to expected positive returns of approximately $14 million.

The following table provides the sensitivities associated with a 100 basis point change in the health care cost trend rate and the discount rate on 2017 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2017 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate

Year Ended December 31, 2017

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

ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in actual cost from forecast to be recovered from, or refunded to, customers in future rates. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2017, for OPEB plans, the Corporation had consolidated accumulated benefit obligations of $665 million (December 31, 2016 – $676 million) and consolidated plan assets of $277 million (December 31, 2016 – $252 million), for a consolidated funded status in a liability position of $388 million (December 31, 2016 – $424 million). In 2017 the Corporation recognized consolidated net OPEB benefit cost of $32 million (2016 – $30 million).

Revenue Recognition: Revenue at the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator.

The unbilled revenue accrual for the period is based on estimated electricity and gas sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of electricity and gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity and gas consumption will result in adjustments to revenue in the periods they become known, when actual results differ from estimates. As at December 31, 2017, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $575 million (December 31, 2016 – $551 million) on consolidated revenue of $8.3 billion for 2017 (2016 – $6.8 billion).

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

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

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court entered a decision dismissing the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the minister's consent and returned the matter to the minister for redetermination. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Comparative Figures in the Consolidated Statement of Cash Flows

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

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

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

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

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. There were no material related-party transactions in 2017 or 2016.

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

Related-party and inter-company transactions

Years Ended December 31

($ millions)	**2017**	2016
Sale of capacity from Waneta Expansion to FortisBC Electric	**46**	45
Sale of energy from BECOL to Belize Electricity	**35**	33
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**24**	17

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

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

SELECTED ANNUAL FINANCIAL INFORMATION

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

Selected Annual Financial Information

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

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

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

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

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

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

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

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

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

FOURTH QUARTER RESULTS

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

Summary of Electricity and Energy Sales and Gas Volumes

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

Electricity and Energy Sales

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

Gas Volumes

Gas volumes were comparable with 2016.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders

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

Revenue

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

Earnings

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

Basic Earnings per Common Share

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

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31

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

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

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

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

SUMMARY OF QUARTERLY RESULTS

The following table sets forth quarterly information for each of the eight quarters ended March 31, 2016 through December 31, 2017. The quarterly information has been obtained from the Corporation's unaudited condensed consolidated interim financial statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results

Quarter Ended	Revenue ($ millions)	Net Earnings Attributable to Common Equity Shareholders ($ millions)	Earnings per Common Share Basic ($)	Earnings per Common Share Diluted ($)
December 31, 2017	2,111	134	0.32	0.31
September 30, 2017	1,901	278	0.66	0.66
June 30, 2017	2,015	257	0.62	0.62
March 31, 2017	2,274	294	0.72	0.72
December 31, 2016	2,053	189	0.49	0.49
September 30, 2016	1,528	127	0.45	0.45
June 30, 2016	1,485	107	0.38	0.38
March 31, 2016	1,772	162	0.57	0.57

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

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

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

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

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

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

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

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

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

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

OUTLOOK

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

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

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

Fortis has targeted average annual dividend growth of approximately 6% through 2022. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure program, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

OUTSTANDING SHARE DATA

As at February 14, 2018, the Corporation had issued and outstanding 421.1 million common shares; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M. Only the common shares of the Corporation have voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options were converted as at February 14, 2018 is approximately 3.7 million.

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

Financials

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Deloitte LLP, an Independent Registered Public Accounting Firm, as auditors of the Corporation's consolidated financial statements for the year ended December 31, 2017, has also audited the effectiveness of the Corporation's internal control over financial reporting as at December 31, 2017. As stated in the Report of Independent Registered Public Accounting Firm, Deloitte LLP expressed an unqualified opinion on the effectiveness of the Corporation's internal control over financial reporting as at December 31, 2017.

Barry Perry

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

Karl Smith

Karl W. Smith
Executive Vice President, Chief Financial Officer, Fortis Inc.

St. John's, Canada
February 14, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Consolidated Financial Statements
We have audited the accompanying consolidated financial statements of Fortis Inc. and subsidiaries (the "Corporation"), which comprise the consolidated balance sheet as at December 31, 2017, the consolidated statement of earnings, consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the year then ended, and the related notes, including a summary of significant accounting policies and other explanatory information (collectively referred to as the "financial statements").

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2017, and its financial performance and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Predecessor Auditor on Prior Period
The consolidated financial statements of the Corporation for the year ended December 31, 2016, were audited by another auditor who expressed an unmodified/unqualified opinion on those financial statements on February 15, 2017, except as to Note 31, which is as of February 14, 2018.

Report on Internal Control over Financial Reporting
We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Corporation's internal control over financial reporting as at December 31, 2017, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 14, 2018 expressed an unqualified opinion on the Corporation's internal control over financial reporting.

Basis for Opinion
Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement, whether due to fraud or error. Those standards also require that we comply with ethical requirements. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. Further, we are required to be independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and to fulfill our other ethical responsibilities in accordance with these requirements.

An audit includes performing procedures to assess the risks of material misstatement of the financial statements, whether due to fraud or error, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Corporation's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies and principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a reasonable basis for our audit opinion.

Deloitte LLP

Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 14, 2018

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Fortis Inc. and subsidiaries (the "Corporation") as at December 31, 2017, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as at December 31, 2017, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB") and Canadian generally accepted auditing standards, the Corporation's consolidated financial statements as at and for the year ended December 31, 2017, and our report dated February 14, 2018, expressed an unmodified/unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Deloitte LLP

Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 14, 2018

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheet as at December 31, 2016, and the consolidated statement of earnings, comprehensive income, cash flows and changes in equity for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audits in accordance with Canadian generally accepted auditing standards and with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2016, and its financial performance and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States.

Ernst + Young LLP

Ernst & Young LLP

Chartered Professional Accountants

St. John's, Canada
February 15, 2017, except as to Note 31,
which is as of February 14, 2018

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)

ASSETS	2017	2016
Current assets		
Cash and cash equivalents	**$ 327**	$ 269
Accounts receivable and other current assets *(Note 6)*	**1,131**	1,127
Prepaid expenses	**79**	85
Inventories *(Note 7)*	**367**	372
Regulatory assets *(Note 8)*	**303**	313
Total current assets	**2,207**	2,166
Other assets *(Note 9)*	**480**	406
Regulatory assets *(Note 8)*	**2,742**	2,620
Property, plant and equipment, net *(Note 10)*	**29,668**	29,337
Intangible assets, net *(Note 11)*	**1,081**	1,011
Goodwill *(Note 12)*	**11,644**	12,364
Total assets	**$ 47,822**	$ 47,904
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings *(Note 14)*	**$ 209**	$ 1,155
Accounts payable and other current liabilities *(Note 13)*	**2,053**	1,970
Regulatory liabilities *(Note 8)*	**490**	492
Current installments of long-term debt *(Note 14)*	**705**	251
Current installments of capital lease and finance obligations *(Note 15)*	**47**	76
Total current liabilities	**3,504**	3,944
Other liabilities *(Note 16)*	**1,210**	1,279
Regulatory liabilities *(Note 8)*	**2,956**	1,691
Deferred income taxes *(Note 23)*	**2,298**	3,263
Long-term debt *(Note 14)*	**20,691**	20,817
Capital lease and finance obligations *(Note 15)*	**414**	460
Total liabilities	**31,073**	31,454
Commitments and Contingencies *(Note 30)*		
Equity		
Common shares [(1)]	**11,582**	10,762
Preference shares *(Note 18)*	**1,623**	1,623
Additional paid-in capital	**10**	12
Accumulated other comprehensive income *(Note 19)*	**61**	745
Retained earnings	**1,727**	1,455
Shareholders' equity	**15,003**	14,597
Non-controlling interests *(Note 20)*	**1,746**	1,853
Total equity	**16,749**	16,450
Total liabilities and equity	**$ 47,822**	$ 47,904

(1) No par value. Unlimited authorized shares; 421.1 million and 401.5 million issued and outstanding as at December 31, 2017 and 2016, respectively

Approved on Behalf of the Board

Douglas J. Haughey, Director

Tracey C. Ball, Director

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2017**	2016
Revenue	**$ 8,301**	$ 6,838
Expenses		
Energy supply costs	**2,361**	2,341
Operating expenses	**2,261**	2,031
Depreciation and amortization	**1,179**	983
Total expenses	**5,801**	5,355
Operating income	**2,500**	1,483
Other income, net *(Note 22)*	**127**	53
Finance charges	**914**	678
Earnings before income tax expense	**1,713**	858
Income tax expense *(Note 23)*	**588**	145
Net earnings	**$ 1,125**	$ 713
Net earnings attributable to:		
Non-controlling interests	**$ 97**	$ 53
Preference equity shareholders	**65**	75
Common equity shareholders	**963**	585
	$ 1,125	$ 713
Earnings per common share *(Note 17)*		
Basic	**$ 2.32**	$ 1.89
Diluted	**$ 2.31**	$ 1.89

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2017**	2016
Net earnings	**$ 1,125**	$ 713
Other comprehensive (loss) income *(Note 19)*		
Unrealized foreign currency translation losses, net of hedging activities and income tax expense of $2 and $nil, respectively	**(781)**	(50)
Available-for-sale investment, net of income tax expense, of $nil and $nil, respectively	**–**	2
Cash flow hedges, net of income tax expense, of $nil and $2, respectively	**2**	3
Employee future benefits, net of income tax expense, of $nil and $nil, respectively	**(4)**	(1)
	(783)	(46)
Comprehensive income	**$ 342**	$ 667
Comprehensive income attributable to:		
Non-controlling interests	**$ (2)**	$ 53
Preference equity shareholders	**65**	75
Common equity shareholders	**279**	539
	$ 342	$ 667

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2017**	2016
Operating activities		
Net earnings	**$ 1,125**	$ 713
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – property, plant and equipment	**1,055**	873
Amortization – intangible assets	**97**	79
Amortization – other	**27**	31
Deferred income tax expense *(Note 23)*	**544**	98
Accrued employee future benefits	**27**	58
Equity component of allowance for funds used during construction *(Note 22)*	**(74)**	(37)
Other	**(16)**	64
Change in long-term regulatory assets and liabilities	**68**	(17)
Change in working capital *(Note 27)*	**(97)**	22
Cash from operating activities	**2,756**	1,884
Investing activities		
Capital expenditures – property, plant and equipment	**(2,813)**	(1,912)
Capital expenditures – intangible assets	**(211)**	(149)
Contributions in aid of construction	**102**	50
Proceeds on sale of assets	**6**	50
Business acquisitions, net of cash acquired *(Note 25)*	**–**	(4,841)
Other	**(109)**	(89)
Cash used in investing activities	**(3,025)**	(6,891)
Financing activities		
Proceeds from long-term debt, net of issuance costs *(Note 14)*	**2,538**	4,136
Repayments of long-term debt and capital lease and finance obligations	**(952)**	(336)
Borrowings under committed credit facilities *(Note 31)*	**2,085**	668
Repayments under committed credit facilities *(Note 31)*	**(2,039)**	(499)
Net repayments and borrowings under committed credit facilities *(Note 31)*	**(365)**	(76)
Net change in short-term borrowings	**(892)**	392
Advances from non-controlling interests	**4**	1,361
Issue of common shares to an institutional investor	**500**	–
Issue of common shares, net of costs, and dividends reinvested	**61**	45
Redemption of preference shares *(Note 18)*	**–**	(200)
Dividends		
Common shares, net of dividends reinvested	**(419)**	(316)
Preference shares	**(65)**	(72)
Subsidiary dividends paid to non-controlling interests	**(109)**	(53)
Other	**(8)**	–
Cash from financing activities	**339**	5,050
Effect of exchange rate changes on cash and cash equivalents	**(12)**	(16)
Change in cash and cash equivalents	**58**	27
Cash and cash equivalents, beginning of year	**269**	242
Cash and cash equivalents, end of year	**$ 327**	$ 269

Supplementary Information to Consolidated Statements of Cash Flows *(Note 27)*

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31, 2017 and 2016 (in millions of Canadian dollars, except share numbers)	**Common Shares**	**Common Shares**	**Preference Shares**	**Additional Paid-In Capital**	**Accumulated Other Comprehensive Income (Loss)**	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
	(# millions)		*(Note 18)*		*(Note 19)*		*(Note 20)*	
As at December 31, 2016	**401.5**	**$ 10,762**	**$ 1,623**	**$ 12**	**$ 745**	**$ 1,455**	**$ 1,853**	**$ 16,450**
Net earnings	**–**	**–**	**–**	**–**	**–**	**1,028**	**97**	**1,125**
Other comprehensive loss	**–**	**–**	**–**	**–**	**(684)**	**–**	**(99)**	**(783)**
Common shares issued under private offering *(Note 14)*	**12.2**	**500**	**–**	**–**	**–**	**–**	**–**	**500**
Common shares issued under dividend reinvestment plan and other	**7.4**	**320**	**–**	**(5)**	**–**	**–**	**–**	**315**
Stock-based compensation	**–**	**–**	**–**	**3**	**–**	**–**	**–**	**3**
Advances from non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**4**	**4**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**(109)**	**(109)**
Dividends declared on common shares ($1.65 per share)	**–**	**–**	**–**	**–**	**–**	**(691)**	**–**	**(691)**
Dividends declared on preference shares	**–**	**–**	**–**	**–**	**–**	**(65)**	**–**	**(65)**
As at December 31, 2017	**421.1**	**$ 11,582**	**$ 1,623**	**$ 10**	**$ 61**	**$ 1,727**	**$ 1,746**	**$ 16,749**
As at December 31, 2015	281.6	$ 5,867	$ 1,820	$ 14	$ 791	$ 1,388	$ 473	$ 10,353
Net earnings	–	–	–	–	–	660	53	713
Other comprehensive loss	–	–	–	–	(46)	–	–	(46)
Common shares issued under public offering *(Notes 25 and 27)*	114.4	4,684	–	–	–	–	–	4,684
Common shares issued under dividend reinvestment plan and other	5.5	211	–	(4)	–	–	–	207
Stock-based compensation	–	–	–	2	–	–	–	2
Advances from non-controlling interests	–	–	–	–	–	–	1,361	1,361
Foreign currency translation impacts	–	–	–	–	–	–	19	19
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	–	(53)	(53)
Redemption of preference shares	–	–	(197)	–	–	–	–	(197)
Dividends declared on common shares ($1.55 per share)	–	–	–	–	–	(534)	–	(534)
Dividends declared on preference shares	–	–	–	–	–	(75)	–	(75)
Adoption of new accounting policy	–	–	–	–	–	16	–	16
As at December 31, 2016	401.5	$ 10,762	$ 1,623	$ 12	$ 745	$ 1,455	$ 1,853	$ 16,450

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

For the years ended December 31, 2017 and 2016

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is principally an international electric and gas utility holding company. Fortis segments its business based on regulatory status and service territory, as well as the information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of the segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, and assumes responsibility for net earnings and its own resource allocation.

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

Regulated Utilities – United States

a. *ITC:* Primarily comprised of ITC Holdings Corp. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC, (collectively "ITC"). ITC was acquired by Fortis in October 2016, with Fortis owning 80.1% of ITC and an affiliate of GIC Private Limited ("GIC") owning a 19.9% minority interest (Notes 20 and 25). Also included in the ITC segment is the net corporate expenses and activity of ITC Investment Holdings.

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

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

   UNS Energy's largest operating subsidiary, TEP, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States. UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to retail customers in Arizona's Mohave and Santa Cruz counties. TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,834 megawatts ("MW"), including 64 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned.

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

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

Regulated Utilities – Canada

a. *FortisBC Energy:* FortisBC Energy Inc. ("FortisBC Energy") is the largest regulated distributor of natural gas in British Columbia, serving more than 135 communities. FortisBC Energy provides transmission and distribution services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FortisBC Energy's Southern Crossing pipeline, from Alberta.

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

1. DESCRIPTION OF BUSINESS (cont'd)

Regulated Utilities – Canada (cont'd)

c. *FortisBC Electric:* Includes FortisBC Inc. ("FortisBC Electric"), an integrated regulated electric utility operating in the southern interior of British Columbia. FortisBC Electric owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia primarily owned by third parties, one of which is the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT").

d. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric"), FortisOntario Inc. ("FortisOntario"), and the Corporation's 49% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Partnership") (Note 9).

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

Regulated Utilities – Caribbean

Caribbean: Includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2016 – 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity") (Note 9). Caribbean Utilities is an integrated regulated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. Caribbean Utilities has an installed diesel-powered generating capacity of 161 MW. Fortis Turks and Caicos is comprised of two integrated regulated electric utilities that provide electricity to certain islands in Turks and Caicos. Fortis Turks and Caicos has a combined diesel-powered generating capacity of 84 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated – Energy Infrastructure

Energy Infrastructure: Primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion, conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The output is sold to BC Hydro and FortisBC Electric under 40-year contracts. Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW, conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Aitken Creek Gas Storage ULC, acquired by Fortis in April 2016, owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company (Note 25). Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet.

In 2016 the Corporation sold its 16-MW run-of-river Walden hydroelectric generating facility ("Walden") (Note 26).

Non-Regulated – Corporate and Other

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

2. NATURE OF REGULATION AND REGULATORY MATTERS

The earnings of the Corporation's utilities are primarily determined under cost of service ("COS") regulation. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When performance-based rate setting ("PBR") mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

The Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8).

The nature of regulation at the Corporation's utilities and their significant regulatory matters are as follows.

ITC

ITC is regulated by the Federal Energy Regulatory Commission ("FERC") under the *Federal Power Act* (United States). Rates are set annually, using FERC-approved cost-based formula rate templates, and remain in effect for one year, which provides timely cost recovery and reduces regulatory lag. The formula rates include an annual true-up mechanism, that compares actual revenue requirements to billed revenues and any over- or under-collections are accrued and reflected in future rates within a two-year period. The formula rates do not require annual FERC approvals, although inputs remain subject to legal challenge with FERC. The common equity component of capital structure for ITC was 60% for 2017 and 2016.

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

In June 2016 the presiding Administrative Law Judge ("ALJ") issued an initial decision on the Second Complaint, recommending a base ROE of 9.70%, with a maximum ROE of 10.68%. The base ROE for the three effected utilities for the period of May 2016 through September 2016 was 12.38% and any authorized adders that were approved prior to the filing of the complaints were collected during this time, up to a maximum of 13.88%.

The initial decision of the ALJ is a non-binding recommendation to FERC and FERC has yet to issue its order on the Second Complaint. In September 2017 certain MISO transmission owners filed a motion for FERC to dismiss the Second Complaint. If the Second Complaint is not dismissed, it is expected that FERC will establish a new going-forward base ROE and range of reasonableness, which will also be used to calculate the refund liability for the Second Refund Period.

As at December 31, 2017, the estimated range of refunds for the Second Refund Period was between US$106 million and US$145 million and ITC has recognized an aggregate estimated regulatory liability of $182 million (US$145 million) (December 31, 2016 – $188 million (US$140 million)) (Note 8 *(xiii)*). The total estimated refund for the Initial Complaint was $158 million (US$118 million), including interest, as at December 31, 2016, which was paid in 2017.

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

2. *NATURE OF REGULATION AND REGULATORY MATTERS (cont'd)*

UNS Energy

UNS Energy is regulated by the Arizona Corporation Commission ("ACC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). UNS Energy uses a historical test year in the establishment of retail electric and gas rates. Retail electric and gas rates are set to provide the utilities with an opportunity to recover their COS and earn a reasonable rate of return on rate base, including an adjustment for the fair value of rate base as required under the laws of the State of Arizona.

General Rate Application
In February 2017 the ACC issued a rate order for new rates for TEP that took effect February 27, 2017 ("2017 Rate Order"). Provisions of the 2017 Rate Order include: (i) an increase in non-fuel base revenue of approximately $108 million (US$81.5 million), including approximately $20 million (US$15 million) of operating costs related to the 50.5% undivided interest in Unit 1 of Springerville Generating Station purchased by TEP in September 2016; (ii) a 7.04% return on original cost rate base, including a cost of equity of 9.75% and an embedded cost of long-term debt of 4.32%; (iii) a common equity component of capital structure of approximately 50%; and (iv) the adoption of proposed depreciation rates which reflect a reduction in the depreciable life for Unit 1 of San Juan Generating Station. Prior to the 2017 Rate Order, effective from July 1, 2013, TEP's allowed ROE was set at 10.0% on a capital structure of 43.5% common equity.

UNS Electric's allowed ROE is set at 9.50% on a capital structure of 52.8% common equity, effective from August 1, 2016, prior to which its allowed ROE was set at 9.50% on a capital structure of 52.6%, effective from January 1, 2014. UNS Gas' allowed ROE is set at 9.75% on a capital structure of 50.8% common equity, effective from May 1, 2012.

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

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

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

Central Hudson

Central Hudson is regulated by the New York State Public Service Commission ("PSC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). Central Hudson uses a future test year in the establishment of rates. Central Hudson's allowed ROE is set at 9.0% on a capital structure of 48% common equity, effective July 1, 2015 for a three-year term.

Effective July 1, 2015, Central Hudson is also subject to an earnings sharing mechanism, whereby the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer.

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

FortisBC Energy and FortisBC Electric

FortisBC Energy and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC") pursuant to the *Utilities Commission Act* (British Columbia), and are subject to Multi-Year PBR Plans for 2014 through 2019. FortisBC Energy is the benchmark utility in British Columbia, as designated by the BCUC, and the established allowed ROE for the benchmark utility is set at 8.75% on a 38.5% common equity component of capital structure, effective January 1, 2016. FortisBC Electric's allowed ROE of 9.15% on a 40% common equity component of capital structure, effective since January 1, 2013, remained unchanged, effective January 1, 2016.

The PBR Plans, as approved by the BCUC, incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FortisBC Energy and 1.03% for FortisBC Electric each year. The approved PBR Plans also include a 50%/50% sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FortisBC Energy and FortisBC Electric maintain specified service levels. It also sets out the requirements for an annual review process which provides a forum for discussion between the utilities and interested parties regarding current performance and future activities.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). FortisAlberta is subject to a Multi-Year PBR plan for 2013 through 2017. Under PBR, each year the prescribed formula is applied to the preceding year's distribution rates, with 2012 used as the going-in distribution rates.

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

Generic Cost of Capital

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

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

Eastern Canadian

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). Newfoundland Power uses a future test year in the establishment of rates. In June 2016 the PUB set the allowed ROE at 8.50%, effective January 1, 2016 and established that Newfoundland Power's common equity component of capital structure of 45% remain unchanged. The June 2016 rate order will remain in effect for 2016 through 2018. Newfoundland Power is required to file its next General Rate Application on or before June 1, 2018.

Maritime Electric is regulated by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI), the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), and the former *Electric Power (Energy Accord Continuation) Amendment Act* (PEI), which expired in February 2016. Maritime Electric uses a future test year for the establishment of rates. In March 2016 IRAC set the Company's allowed ROE at 9.35%, effective March 1, 2016 for a three-year period, down from 9.75% in effect since March 1, 2013, and established that Maritime Electric's targeted capital structure of 40% remain unchanged.

FortisOntario's three electric utilities operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). FortisOntario's utilities use a future test year in the establishment of rates. Earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target as prescribed by the OEB. The allowed ROE for distribution assets for FortisOntario's utilities ranged from 8.78% to 9.30% for 2017 and 8.93% to 9.30% for 2016, both on a deemed capital structure of 40% common equity, with the exception of one of its utilities which is subject to a rate-setting mechanism under a 35-year Franchise Agreement expiring in 2033, based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

2. *NATURE OF REGULATION AND REGULATORY MATTERS (cont'd)*

Regulated Utilities – Caribbean

Caribbean Utilities operates under transmission and distribution and generation licences from the Government of the Cayman Islands. The exclusive transmission and distribution licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. A non-exclusive generation licence was issued for a term of 25 years, expiring November 2039. The licences detail the role of the Cayman Islands Utility Regulation and Competition Office ("OfReg"), which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism ("RCAM"), and annually approves capital expenditures. The licences contain the provision for an RCAM based on published consumer price indices. Caribbean Utilities' targeted allowed ROA for 2017 and 2016 was in the range of 6.75% to 8.75%. In January 2017 a merger of regulatory bodies in the Cayman Islands, including the Electricity Regulatory Authority, resulted in the establishment of OfReg and this merger did not impact the terms and conditions of the licences.

Fortis Turks and Caicos operates under two 50-year licences expiring in 2036 and 2037. Among other matters, the licences describe how electricity rates are set by the Government of the Turks and Caicos Islands, using a historical test year, in order to provide the utilities with an allowed ROA of between 15.0% and 17.5% (the "Allowable Operating Profit"). The Allowable Operating Profit is based on a calculated rate base, including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall"). Annual submissions are made to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The recovery of the Cumulative Shortfall is dependent on future sales volumes and expenses. The achieved ROAs at the utilities have been significantly lower than those allowed under the licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"), which for regulated utilities include specific accounting guidance for regulated operations, as outlined in Note 2, and the following summary of significant accounting policies.

All amounts presented are in Canadian dollars unless otherwise stated.

Basis of Presentation

The consolidated financial statements reflect the Corporation's investments in its subsidiaries and variable interest entity, where Fortis is the primary beneficiary, on a consolidated basis, with the equity method used for entities in which Fortis has significant influence, but not control, and proportionate consolidation for generation and transmission assets that are jointly owned with non-affiliated entities. Intercompany transactions have been eliminated in the consolidated financial statements, except for transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. For further details on the Corporation's variable interest entity refer to Note 29.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

Fortis and each of its subsidiaries, with the exception of ITC, maintain an allowance for doubtful accounts that is estimated based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy and economic conditions. ITC recognizes losses for uncollectible accounts based upon specific identification of such items. Accounts receivable are written-off in the period in which the receivable is deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and net realizable value. The cost of inventory at the Corporation's utilities is expected to be recovered in customer rates.

Regulatory Assets and Liabilities

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

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Investments

Investments in which the Corporation exercises significant influence are accounted for on the equity basis. The Corporation reviews its investments on an annual basis for potential impairment in investment value. Any impairment will be recognized in the period in which such impairment is identified.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation. Contributions in aid of construction represent amounts contributed by customers and governments for the cost of property, plant and equipment. These contributions are recorded as a reduction in the cost of property, plant and equipment and are being amortized annually by an amount equal to the charge for depreciation provided on the related assets.

Depreciation rates of the Corporation's regulated utilities include an estimate for future asset removal costs that have not been identified as a legal obligation, with the amount provided for in depreciation expense recorded as a long-term regulatory liability (Note 8 *(xii)*). Actual asset removal costs are recorded against the regulatory liability when incurred.

For the majority of the Corporation's regulated utilities, property, plant and equipment are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal, any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation, with no gain or loss recognized in earnings. It is expected that any gains or losses charged to accumulated depreciation will be reflected in future depreciation expense when they are refunded or collected in customer rates.

The majority of the Corporation's regulated utilities capitalize overhead costs that are not directly attributable to specific property, plant and equipment but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized overhead costs to property, plant and equipment is established by the respective regulator.

The majority of the Corporation's regulated utilities include in the cost of property, plant and equipment both a debt and an equity component of the allowance for funds used during construction ("AFUDC"). The debt component of AFUDC totalling $38 million (2016 – $29 million) is reported as a reduction of finance charges and the equity component of AFUDC is reported as other income (Note 22). Both components of AFUDC are charged to earnings through depreciation expense over the estimated service lives of the applicable asset. AFUDC is calculated in a manner as prescribed by the respective regulator.

At FortisAlberta the cost of property, plant and equipment also includes Alberta Electric System Operator ("AESO") contributions, which are investments required by FortisAlberta to partially fund the construction of transmission facilities.

Property, plant and equipment include inventories held for the development, construction and betterment of other assets, with the exception of UNS Energy. As required by its regulator, UNS Energy recognizes inventories held for the development and construction of other assets in inventories until consumed. When put into service, the inventories are reclassified to property, plant and equipment.

Maintenance and repairs of property, plant and equipment are charged to earnings in the period incurred, while replacements and betterments that extend the useful lives are capitalized.

Property, plant and equipment is depreciated using the straight-line method based on the estimated service lives of the asset. Depreciation rates for regulated property, plant and equipment are approved by the respective regulator. Depreciation rates for 2017 ranged from 0.9% to 34.6% (2016 – 0.9% to 34.6%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, for 2017 was 2.6% (2016 – 2.8%).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Property, Plant and Equipment (cont'd)

The service life ranges and weighted average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows.

	2017		2016	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5–80**	**33**	5-80	32
Gas	**14–95**	**34**	7–95	33
Transmission				
Electric	**20–80**	**41**	20–80	41
Gas	**5–80**	**34**	7–80	34
Generation	**5–85**	**28**	5–85	26
Other	**3–70**	**14**	3–70	14

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Capital leases are depreciated over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case capital leases are depreciated over the estimated service life of the underlying asset. Where the regulator has approved recovery of the arrangements as operating leases for rate-setting purposes that would otherwise qualify as capital leases for financial reporting purposes, the timing of the expense recognition related to the lease is modified to conform with the rate-setting process.

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

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually, either individually or at the reporting unit level. Such intangible assets are not amortized. An intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulator. Amortization rates for 2017 ranged from 1.0% to 50.0% (2016 – 1.0% to 50.0%).

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

	2017		2016	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3–10**	**4**	3–10	4
Land, transmission and water rights	**36–80**	**57**	30–80	57
Other	**10–100**	**10**	10–104	15

For the majority of the Corporation's regulated utilities, intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization, with no gain or loss recognized in earnings. It is expected that any gains or losses charged to accumulated amortization will be reflected in future amortization costs when they are refunded or collected in customer rates.

The majority of indefinite-lived intangible assets are held in the Corporation's regulated utilities that also have goodwill. For its annual testing of impairment for indefinite-lived intangible assets, Fortis includes these assets as part of the respective reporting units, which are tested on an annual basis for goodwill impairment, as disclosed in this Note under "Goodwill".

Impairment of Long-Lived Assets

The Corporation reviews the valuation of property, plant and equipment, intangible assets with finite lives, and other long-term assets when events or changes in circumstances indicate that the assets' carrying value may not be recoverable. If the carrying amount of the asset exceeds the expected total undiscounted cash flows generated by the asset, the asset is written down to estimated fair value and an impairment loss is recognized in earnings in the period in which it is identified.

Asset-impairment testing is carried out at the reporting unit level to determine if assets are impaired. The net cash flows for reporting units are not asset-specific but are pooled for the entire reporting unit. The recovery of regulated assets' carrying value, including a fair rate of return, is provided through customer rates approved by the respective regulatory authority.

Goodwill

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

Fortis performs an annual internal qualitative and quantitative assessment for each reporting unit to which goodwill has been allocated. The Corporation has a total of 11 reporting units that were allocated goodwill at the respective dates of acquisition by Fortis. For those reporting units where: (i) management's assessment of qualitative and quantitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year.

In calculating goodwill impairment, the estimated fair value of the reporting unit is compared to its carrying value. If the fair value of the reporting unit is less than the carrying value, the excess of the carrying amount over fair value is recorded as goodwill impairment, not to exceed the total amount of goodwill allocated to the reporting unit.

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

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

Deferred Financing Costs

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

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, including retirement allowances and supplemental retirement plans for certain executive employees, and defined contribution pension plans, including group Registered Retirement Savings Plans and group 401(k) plans for employees. The projected benefit obligation and the value of pension cost associated with the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and expected retirement ages of employees. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments.

With the exception of FortisBC Energy and Newfoundland Power, pension plan assets are valued at fair value for the purpose of determining pension cost. At FortisBC Energy and Newfoundland Power, pension plan assets are valued using the market-related value for the purpose of determining pension cost, where investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

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

3. *SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)*

Employee Future Benefits (cont'd)

Defined Benefit and Defined Contribution Pension Plans (cont'd)
The net funded or unfunded status of defined benefit pension plans, measured as the difference between the fair value of the plan assets and the projected benefit obligation, is recognized on the Corporation's consolidated balance sheet.

For the majority of the Corporation's regulated utilities, any difference between pension cost recognized under US GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*).

With the exception of Fortis and FHI, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8 *(ii)*). At Fortis and FHI, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans are recognized in accumulated other comprehensive income.

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

Other Post-Employment Benefits Plans
The Corporation and its subsidiaries also offer other post-employment benefits ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The accumulated benefit obligation and the cost associated with OPEB plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan performance, salary escalation, expected retirement ages of employees and health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected OPEB payments.

The excess of any cumulative net actuarial gain or loss over 10% of the accumulated benefit obligation and the fair value of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

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

For the majority of the Corporation's regulated utilities, any difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*).

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its stock option plans (Note 21). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and each grant is amortized as a single award evenly over the four-year vesting period of the options granted. The offsetting entry is an increase to additional paid-in capital for an amount equal to the annual compensation expense related to the issuance of stock options. The stock options become exercisable once time-vesting requirements have been met. Upon exercise, the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock. An exercise of options below the current market price of the Corporation's common shares has a dilutive effect on the Corporation's consolidated capital stock and shareholders' equity. Fortis satisfies stock option exercises by issuing common shares from treasury.

The Corporation also records liabilities associated with its Directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans, all representing cash-settled awards, at fair value at each reporting date until settlement. Compensation expense is recognized on a straight-line basis over the vesting period, which for the PSU and RSU Plans is over the shorter of three years or the period to retirement eligibility and for the DSU Plan is at the time of grant. Forfeitures are accounted for as they occur. The fair value of the DSU, PSU and RSU liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP of the Corporation's common shares as at December 31, 2017 was $46.01 (December 31, 2016 – $41.46). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

Foreign Currency Translation

The assets and liabilities of the Corporation's foreign operations, all of which have a US dollar functional currency, are translated at the exchange rate in effect as at the balance sheet date. The exchange rate in effect as at December 31, 2017 was US$1.00=CAD$1.25 (December 31, 2016 – US$1.00=CAD$1.34). The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive income until the foreign subsidiary is sold, substantially liquidated or evaluated for impairment in anticipation of disposal. Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate in effect during the reporting period, which was US$1.00=CAD$1.30 for 2017 (2016 – US$1.00=CAD$1.33).

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are accumulated as a separate component of shareholders' equity within accumulated other comprehensive income and the current period change is recorded in other comprehensive income.

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

Derivative Instruments and Hedging Activities

Non-Designated Derivatives

Derivatives not designated as hedging contracts are used by Fortis to manage cash flow risk associated with forecasted US dollar cash inflows and forecasted future cash settlements of DSU and RSU obligations; UNS Energy to meet forecast load and reserve requirements; and Aitken Creek to manage exposure to commodity price risk, to capture natural gas price spreads, and to manage the financial risk posed by physical transactions. These non-designated derivatives are measured at fair value with changes in fair value recognized in earnings.

Derivatives not designated as hedging contracts are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce exposure to energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These non-designated derivatives are measured at fair value and the net unrealized gains and losses associated with changes in fair value of the derivative contracts are recorded as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8 *(viii)*).

Derivative instruments that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized as energy supply costs on the consolidated statements of earnings.

Derivatives in Designated Hedging Relationships

For derivatives designated as hedging contracts, the Corporation and its utilities formally assess, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The hedging strategy by transaction type and risk management strategy is formally documented. As at December 31, 2017, the Corporation's hedging relationships primarily consisted of cash flow hedges and net investment hedges.

The Corporation, ITC and UNS Energy use cash flow hedges to manage its exposure to interest rate risk. Unrealized gains or losses on these derivatives are initially recognized in accumulated other comprehensive income and reclassified to earnings when the underlying hedged transaction affects earnings. Any hedge ineffectiveness is recognized in net earnings immediately at the time the gain or loss on the derivatives is calculated.

The Corporation's earnings from, and net investments in, foreign subsidiaries and equity method investments are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased a portion of the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The Corporation has designated its corporately issued US dollar long-term debt as a hedge of a portion of the foreign exchange risk related to its foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as hedges are recognized in accumulated other comprehensive income and help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which gains and losses are also recognized in accumulated other comprehensive income.

Presentation of Derivatives

The fair value of derivative instruments is recognized on the Corporation's consolidated balance sheet as current or long-term assets and liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Derivative contracts under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

3. *SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)*

Income Taxes

The Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not to be realized. Valuation allowances are recognized against deferred tax assets when it is more likely than not that a portion of, or the entire amount of, the deferred income tax asset will not be realized. Deferred income tax assets and liabilities are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the respective regulator, ITC, UNS Energy, Central Hudson and Maritime Electric recover current and deferred income tax expense in customer rates. As approved by the regulator, FortisAlberta recovers income tax expense in customer rates based only on income taxes that are currently payable. FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax expense is recovered from, or refunded to, customers in current rates, as prescribed by the respective regulator. Deferred income taxes that are expected to be collected from or refunded to customers in rates once income taxes become payable or receivable are recognized as a regulatory asset or liability (Note 8 *(i)*).

For regulatory reporting purposes, the capital cost allowance pool for certain property, plant and equipment at FortisAlberta is different from that for legal entity corporate income tax filing purposes. In a future reporting period, yet to be determined, the difference may result in higher income tax expense than that recognized for regulatory rate-setting purposes and collected in customer rates.

Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize for the terms of its 50-year PPAs.

Any difference between the income tax expense recognized under US GAAP and that recovered from customers in current rates that is expected to be recovered from customers in future rates, is subject to deferral account treatment (Note 8 *(i)*).

The Corporation intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, the Corporation does not provide for deferred income taxes on temporary differences related to investments in foreign subsidiaries. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $561 million as at December 31, 2017 (December 31, 2016 – $525 million). If such earnings are repatriated, in the form of dividends or otherwise, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

Tax benefits associated with income tax positions taken, or expected to be taken, in an income tax return are recognized only when the more likely than not recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement. The difference between a tax position taken, or expected to be taken, and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Income tax interest and penalties are expensed as incurred and included in income tax expense.

Sales Taxes

In the course of its operations, the Corporation's subsidiaries collect sales taxes from their customers. When customers are billed, a current liability is recognized for the sales taxes included on customers' bills. The liability is settled when the taxes are remitted to the appropriate government authority. The Corporation's revenue excludes sales taxes.

Revenue Recognition

Revenue from the sale and delivery of electricity and gas by the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed, which is estimated and accrued as revenue.

ITC's transmission revenue is recognized as services are provided based on FERC-approved cost-based formula rate templates. A reserve for revenue subject to refund is recognized as a reduction to revenue when such refund is probable and can be reasonably estimated (Note 8 *(vi)*).

In certain circumstances, UNS Energy and Aitken Creek enter into purchased power and wholesale sales contracts that are not settled with energy. The net sales contracts and power purchase contracts are reflected at the net amount in revenue.

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with the AESO and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. FortisAlberta is not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers are deferred to be recovered from, or refunded to, customers in future rates.

FortisBC Electric has entered into contracts to sell surplus capacity that may be available after it meets its load requirements. This revenue is recognized on an accrual basis at rates established in the sales contract.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements.

Revenue at Aitken Creek is generated from long-term lease storage, park and loan activities, and storage optimization activities and is generally recognized on an accrual basis over the term of the related contracts. Optimization revenue results from the purchase of natural gas and its forward sale through financial and physical trading contracts and consists of realized and unrealized gains and losses on the financial and physical energy trading contracts, not designated as derivatives, used to manage commodity price risk (Note 28).

Asset Retirement Obligations

A conditional asset retirement obligation ("ARO") is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the Corporation's control. AROs are recorded as a liability at fair value and are classified as long-term other liabilities, with a corresponding increase to property, plant and equipment. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. Fair value is based on an estimate of the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recorded through accretion, and the capitalized cost is depreciated over the useful life of the asset. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities.

The Corporation's subsidiaries have AROs associated with the remediation of generation facilities, interconnection facilities, wholesale energy supply agreements, and certain electricity distribution system assets. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time. These assets are reasonably expected to operate in perpetuity due to the nature of their operations. The licences, permits, interconnection facilities agreements, wholesale energy supply agreements and rights-of-way are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Contingencies

Reserves for specific legal proceedings are established when the likelihood of an unfavourable outcome is probable and the amount of loss can be reasonably estimated. Significant judgment is required in predicting the outcome of these claims. The Corporation identifies certain other legal matters where the Corporation believes an unfavourable outcome is reasonably possible or no estimate of possible losses can be made. All contingencies are regularly reviewed to determine whether the likelihood of loss has changed and to assess whether a reasonable estimate of the loss or range of loss can be made.

New Accounting Policies

Simplifying the Test for Goodwill Impairment

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

Inventories

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

Use of Accounting Estimates

The preparation of the consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, they are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities; Property, Plant and Equipment; Intangible Assets; Goodwill; Employee Future Benefits; Income Taxes; Revenue Recognition; and Contingencies, and in the respective notes to the consolidated financial statements.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

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

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update, along with additional ASUs issued in 2016 and 2017 to clarify implementation guidance, create Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard clarifies the principles for recognizing revenue and enables users of financial statements to better understand and consistently analyze an entity's revenues across industries and transactions. The new guidance permits two methods of adoption: (i) the full retrospective method; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption supplemented by additional disclosures. This standard is effective for annual and interim periods beginning after December 15, 2017. Fortis adopted this ASU on January 1, 2018 using the modified retrospective approach and there have been no material adjustments identified to opening retained earnings.

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

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

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

Recognition and Measurement of Financial Assets and Financial Liabilities

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

4. FUTURE ACCOUNTING PRONOUNCEMENTS (cont'd)

Leases

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

Measurement of Credit Losses on Financial Instruments

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

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

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

Targeted Improvements to Accounting for Hedging Activities

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

5. SEGMENTED INFORMATION

Fortis segments its business based on regulatory status and service territory, as well as the information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each segment. Segment performance is evaluated based on net earnings attributable to common equity shareholders.

A detailed description of each reportable segment is provided in Note 1.

	REGULATED									NON-REGULATED			
	United States			Canada									
Year Ended December 31, 2017 *($ millions)*	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean	**Total**	**Energy Infra-structure**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Revenue	1,575	2,080	872	1,198	600	398	1,062	301	**8,086**	**226**	**1**	**(12)**	**8,301**
Energy supply costs	–	711	260	411	–	142	692	144	**2,360**	**2**	**–**	**(1)**	**2,361**
Operating expenses	436	609	402	298	198	89	134	44	**2,210**	**49**	**13**	**(11)**	**2,261**
Depreciation and amortization	220	260	65	198	190	62	95	55	**1,145**	**32**	**2**	**–**	**1,179**
Operating income	919	500	145	291	212	105	141	58	**2,371**	**143**	**(14)**	**–**	**2,500**
Other income, net	40	19	8	20	2	1	1	7	**98**	**1**	**29**	**(1)**	**127**
Finance charges	259	101	41	116	93	37	56	18	**721**	**5**	**189**	**(1)**	**914**
Income tax expense	371	148	42	40	1	14	22	–	**638**	**19**	**(69)**	**–**	**588**
Net earnings	329	270	70	155	120	55	64	47	**1,110**	**120**	**(105)**	**–**	**1,125**
Non-controlling interests	57	–	–	1	–	–	–	13	**71**	**26**	**–**	**–**	**97**
Preference share dividends	–	–	–	–	–	–	–	–	**–**	**–**	**65**	**–**	**65**
Net earnings attributable to common equity shareholders	272	270	70	154	120	55	64	34	**1,039**	**94**	**(170)**	**–**	**963**
Goodwill	7,698	1,733	566	913	227	235	67	178	**11,617**	**27**	**–**	**–**	**11,644**
Total assets	17,581	8,596	3,188	6,418	4,454	2,197	2,489	1,325	**46,248**	**1,605**	**76**	**(107)**	**47,822**
Capital expenditures	982	534	220	446	414	105	156	146	**3,003**	**21**	**–**	**–**	**3,024**
Year Ended December 31, 2016 *($ millions)*													
Revenue	334	2,002	849	1,151	572	377	1,063	301	6,649	193	9	(13)	6,838
Energy supply costs	–	740	253	347	–	132	698	137	2,307	35	–	(1)	2,341
Operating expenses	151	605	387	295	189	88	136	45	1,896	39	108	(12)	2,031
Depreciation and amortization	46	264	61	198	180	57	91	54	951	28	4	–	983
Operating income	137	393	148	311	203	100	138	65	1,495	91	(103)	–	1,483
Other income, net	9	7	5	17	3	–	2	9	52	2	–	(1)	53
Finance charges	54	102	40	125	85	37	55	15	513	4	162	(1)	678
Income tax expense	20	99	43	51	–	9	21	–	243	3	(101)	–	145
Net earnings	72	199	70	152	121	54	64	59	791	86	(164)	–	713
Non-controlling interests	13	–	–	1	–	–	–	13	27	26	–	–	53
Preference share dividends	–	–	–	–	–	–	–	–	–	–	75	–	75
Net earnings attributable to common equity shareholders	59	199	70	151	121	54	64	46	764	60	(239)	–	585
Goodwill	8,246	1,854	605	913	227	235	67	190	12,337	27	–	–	12,364
Total assets	18,000	8,935	3,214	6,230	4,057	2,143	2,394	1,344	46,317	1,502	130	(45)	47,904
Capital expenditures	223	524	233	336	375	74	161	106	2,032	19	10	–	2,061

5. SEGMENTED INFORMATION (cont'd)

Related-party and inter-company transactions

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. There were no material related-party transactions in 2017 or 2016.

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

(in millions)	**2017**	2016
Sale of capacity from Waneta Expansion to FortisBC Electric	**$ 46**	$ 45
Sale of energy from BECOL to Belize Electricity	**35**	33
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**24**	17

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

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

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	**2017**	2016
Trade accounts receivable	**$ 492**	$ 507
Unbilled accounts receivable	**575**	551
Allowance for doubtful accounts	**(31)**	(33)
Income tax receivable	**8**	26
Other	**87**	76
	$ 1,131	$ 1,127

Other consisted of customer billings for non-core services, collateral deposits for gas purchases at FortisBC Energy, advances on coal purchases at UNS Energy, and the fair value of derivative instruments (Note 28).

7. INVENTORIES

(in millions)	**2017**	2016
Materials and supplies	**$ 238**	$ 244
Gas and fuel in storage	**97**	98
Coal inventory	**32**	30
	$ 367	$ 372

8. REGULATORY ASSETS AND LIABILITIES

Based on previous, existing or expected regulatory orders or decisions, the Corporation's regulated utilities have recognized the following amounts that are expected to be recovered from, or refunded to, customers in future periods.

(in millions)	**2017**	2016	Remaining recovery period *(years)*
Regulatory assets			
Deferred income taxes *(i)*	**$ 1,403**	$ 1,260	To be determined
Employee future benefits *(ii)*	**510**	576	Various
Deferred energy management costs *(iii)*	**200**	178	1–10
Generation early retirement costs *(iv)*	**105**	–	11–13
Deferred lease costs *(v)*	**104**	97	Various
Rate stabilization accounts *(vi)*	**95**	183	Various
Deferred operating overhead costs *(vii)*	**91**	78	Various
Derivative instruments *(viii)*	**87**	19	Various
Manufactured gas plant ("MGP") site remediation deferral *(ix)*	**75**	107	To be determined
Greenhouse gas reduction regulatory incentives *(x)*	**35**	40	10
Other regulatory assets *(xi)*	**340**	395	Various
Total regulatory assets	**3,045**	2,933	
Less: current portion	**(303)**	(313)	1
Long-term regulatory assets	**$ 2,742**	$ 2,620	
Regulatory liabilities			
Deferred income taxes *(i)*	**$ 1,484**	$ –	To be determined
Asset removal cost provision *(xii)*	**1,095**	1,194	To be determined
Rate stabilization accounts *(vi)*	**254**	230	Various
ROE refund liability *(xiii)*	**182**	346	1
Energy efficiency liability *(xiv)*	**82**	49	Various
Renewable energy surcharge *(xv)*	**66**	53	To be determined
Electric and gas moderator account *(xvi)*	**58**	71	To be determined
Employee future benefits *(ii)*	**47**	42	Various
Other regulatory liabilities *(xvii)*	**178**	198	Various
Total regulatory liabilities	**3,446**	2,183	
Less: current portion	**(490)**	(492)	1
Long-term regulatory liabilities	**$ 2,956**	$ 1,691	

Description of the Nature of Regulatory Assets and Liabilities

(i) *Deferred Income Taxes*

The Corporation's regulated utilities recognize deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future rates. As at December 31, 2017, regulatory assets of approximately $754 million associated with deferred income taxes were not subject to a regulatory return (December 31, 2016 – $596 million). As at December 31, 2017, regulatory liabilities of approximately $1,481 million associated with deferred taxes were not subject to a regulatory return.

The balances for ITC, UNS Energy and Central Hudson reflect the effects of the significant changes to tax legislation signed into law in the United States in December 2017 ("U.S. Tax Reform"). As part of U.S. Tax Reform, utilities were required to remeasure their deferred income tax assets and liabilities (Note 23). Included in regulatory liabilities is $1,453 million related to U.S. Tax Reform, reflecting the reduction in deferred income tax expense expected to be refunded to customers.

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(ii) Employee Future Benefits

The regulatory asset and liability associated with employee future benefits includes the actuarially determined unamortized net actuarial losses, past service costs and credits, and transitional obligations associated with defined benefit pension and OPEB plans maintained by the Corporation's regulated utilities (Note 24), which are expected to be recovered from, or refunded to, customers in future rates. At the Corporation's regulated utilities, as approved by the respective regulators, differences between defined benefit pension and OPEB plan costs recognized under US GAAP and those which are expected to be recovered from, or refunded to, customers in future rates are subject to deferral account treatment and have been recognized as a regulatory asset or liability. These amounts would otherwise be recognized in accumulated other comprehensive income on the consolidated balance sheet.

As at December 31, 2017, regulatory assets of approximately $291 million associated with employee future benefits were not subject to a regulatory return (December 31, 2016 – $346 million). As at December 31, 2017, regulatory liabilities of approximately $45 million associated with employee future benefits were not subject to a regulatory return (December 31, 2016 – $31 million).

(iii) Deferred Energy Management Costs

FortisBC Energy, FortisBC Electric, Central Hudson and Newfoundland Power provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, these regulated utilities have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from 1 to 10 years. This regulatory asset represents the unamortized balance of the energy management costs.

UNS Energy is required to implement cost-effective Demand-Side Management ("DSM") programs to comply with the ACC's energy efficiency standards. The energy efficiency standards provide for a DSM surcharge to recover the costs of implementing DSM programs, as well as an annual performance incentive. The existing rate orders provide for a lost fixed-cost recovery mechanism to recover certain non-fuel costs that were previously unrecoverable, due to reduced electricity sales as a result of energy efficiency programs and distributed generation.

As at December 31, 2017, $41 million of the regulatory asset balance associated with deferred energy management costs was not subject to a regulatory return (December 31, 2016 – $42 million).

(iv) Generation Early Retirement Costs

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

UNS Energy owns the Sundt Generating Facility ("Sundt") and in August 2017 TEP submitted an application related to a generation modernization project at the facility, which will add generation capacity in the form of gas-fired reciprocating engines. As part of the application, TEP plans to early retire Sundt Units 1 and 2 by the end of 2020. Capital and operating costs related to Sundt Units 1 and 2 are currently being recovered through to 2028 and 2030, respectively.

As a result of the planned early retirement of Navajo and Sundt Units 1 and 2, the net book value and other related retirement costs were reclassified from property, plant and equipment to regulatory assets, and as at December 31, 2017 the net book value of these assets was $105 million (US$84 million). UNS Energy's generation early retirement costs are not subject to regulatory return.

(v) Deferred Lease Costs

Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA"), which ends in 2056. The depreciation of the asset under capital lease and interest expense associated with the capital lease obligation are not being fully recovered in current customer rates, since those rates include only the cash payments set out under the BPPA (Note 15). The deferred lease costs are expected to be recovered from customers in future rates over the term of the lease and are not subject to a regulatory return.

In 2017, of the $31 million (2016 – $31 million) of interest expense related to the capital lease obligations and the $6 million (2016 – $6 million) of depreciation expense related to the assets under capital lease, $27 million (2016 – $27 million) was recognized in energy supply costs and $3 million (2016 – $3 million) was recognized in operating expenses, as approved by the regulator, with the balance of $7 million (2016 – $7 million) deferred as a regulatory asset.

(vi) *Rate Stabilization Accounts*

Rate stabilization accounts associated with the Corporation's regulated utilities are recovered from, or refunded to, customers in future rates, as approved by the respective regulators. Electric rate stabilization accounts primarily mitigate the effect on earnings of variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level and, at certain utilities, revenue decoupling mechanisms minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented. Gas rate stabilization accounts primarily mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather, and natural gas cost volatility.

At ITC, transmission revenue requirements are set annually using cost-based formula rates that remain in effect for a one-year period. The formula rates include a true-up mechanism, whereby the actual revenue requirement is compared to billed revenue for each year to determine any over- or under-collection of revenue requirement. Revenue is recognized based on the actual revenue requirement, and revenue accrual and deferral accounts represent the difference between the actual revenue requirement and billed revenue, and are collected from, or refunded to, customers within a two-year period.

As at December 31, 2017, approximately $75 million and $144 million of the rate stabilization accounts are expected to be recovered from, or refunded to, customers within one year and, as a result, are classified as current regulatory assets and liabilities, respectively (December 31, 2016 – approximately $135 million and $173 million, respectively).

As at December 31, 2017, regulatory assets of approximately $91 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2016 – $139 million). As at December 31, 2017, regulatory liabilities of approximately $114 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2016 – $180 million).

(vii) *Deferred Operating Overhead Costs*

As approved by the regulator, FortisAlberta has deferred certain operating overhead costs, which are expected to be collected in future customer rates over the lives of the related property, plant and equipment and intangible assets.

(viii) *Derivative Instruments*

As approved by the respective regulators, unrealized gains or losses associated with changes in the fair value of certain derivative instruments at UNS Energy, Central Hudson and FortisBC Energy are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. These unrealized losses and gains would otherwise be recognized in earnings. UNS Energy and Central Hudson's regulatory asset balance totalling $38 million as at December 31, 2017 was not subject to a regulatory return (December 31, 2016 – $6 million).

(ix) *MGP Site Remediation Deferral*

As approved by the regulator, Central Hudson is permitted to defer for future recovery from its customers the difference between actual costs for MGP site investigation and remediation and the associated rate allowances (Notes 13 and 16). Central Hudson's MGP site remediation costs are not subject to a regulatory return.

(x) *Greenhouse Gas Reduction Regulatory Incentives*

The deferral for greenhouse gas reduction regulatory incentives at FortisBC Energy is mostly comprised of subsidy payments to assist customers to purchase natural gas vehicles in lieu of vehicles fuelled by diesel as part of the incentive program pursuant to the Greenhouse Gas Reductions (Clean Energy) Regulations under the *Clean Energy Act* (British Columbia). The regulator has approved recovery in rates over a 10-year period.

(xi) *Other Regulatory Assets*

Other regulatory assets relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $40 million. As at December 31, 2017, $306 million (December 31, 2016 – $296 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2017, $145 million (December 31, 2016 – $217 million) of the balance was not subject to a regulatory return.

(xii) *Asset Removal Cost Provision*

As required by the respective regulators, depreciation rates include an accrual for asset removal costs. Actual asset removal costs are recorded against the regulatory liability when incurred. This regulatory liability represents amounts collected in customer rates in excess of incurred asset removal costs.

(xiii) *ROE Refund Liability*

The ROE refund liability at ITC relates to two third-party complaints pending before FERC requesting that the MISO regional base ROE for MISO transmission owners, including ITC, be found to no longer be just and reasonable. The complaints cover two consecutive 15-month periods from November 2013 through February 2015 and February 2015 through May 2016 (Note 2). As at December 31, 2017, the estimated range of refunds for the Second Complaint was between US$106 million and US$145 million and ITC has recognized an estimated liability of $182 million (US$145 million), which has been classified as current regulatory liability. The total estimated refund for the Initial Complaint was $158 million (US$118 million), including interest, as at December 31, 2016, which was substantially finalized and paid in 2017.

8. *REGULATORY ASSETS AND LIABILITIES (cont'd)*

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xiv) *Energy Efficiency Liability*

The energy efficiency liability primarily relates to Central Hudson's Energy Efficiency Program established to fund the costs of environmental policies associated with energy conservation programs and megawatt hour reduction goals, as approved by its regulator, and was not subject to a regulatory return.

(xv) *Renewable Energy Surcharge*

As ordered by the regulator under its Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. The Company must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out the plan is recovered from retail customers through the RES surcharge until such costs are reflected in TEP and UNS Electric's non-fuel base rates. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory asset or liability and are subject to a regulatory return.

The ACC measures compliance with its RES requirements through Renewable Energy Credits ("REC"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records the cost of the RECs as long-term other assets (Note 9) and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, energy supply costs and revenue are recognized in an equal amount.

(xvi) *Electric and Gas Moderator Account*

Under the terms of Central Hudson's three-year Rate Order issued in June 2015, certain of the Company's regulatory assets and liabilities were identified and approved by the PSC for offset and a net regulatory liability electric and gas moderator account was established, which will be used for future customer rate moderation. This electric and gas moderator account was not subject to a regulatory return.

(xvii) *Other Regulatory Liabilities*

Other regulatory liabilities relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $40 million. As at December 31, 2017, $173 million (December 31, 2016 – $190 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2017, $26 million (December 31, 2016 – $51 million) of the balance was not subject to a regulatory return.

9. OTHER ASSETS

(in millions)	**2017**	2016
Supplemental Executive Retirement Plan assets	**$ 130**	$ 115
Equity investment – Belize Electricity	**73**	78
Renewable Energy Credits *(Note 8 (xv))*	**62**	39
Defined benefit pension plan assets *(Note 24)*	**31**	32
Other investments	**29**	21
Deferred compensation plan assets	**24**	24
Equity investment – Wataynikaneyap Partnership	**22**	3
Other [(1)]	**109**	94
	$ 480	$ 406

[(1)] Other assets are generally recorded at cost and recovered/amortized over the estimated period of future benefit, where applicable. Other assets also includes the fair value of derivative instruments (Note 28).

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through both deferred compensation plans for Directors and Officers of the Companies, as well as Supplemental Executive Retirement Plans ("SERP") and the assets held to support these plans are reported separately from the related liabilities (Note 16). Most of the plan assets are held in trust and funded mainly through the use of trust-owned life insurance policies and mutual funds. Assets held in mutual and money market funds are recorded at fair value on a recurring basis (Note 28). Included in SERP assets are available-for-sale-securities at ITC of $66 million (2016 – $56 million), for which gains and losses are recorded in other comprehensive income.

10. PROPERTY, PLANT AND EQUIPMENT

2017

(in millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Distribution			
Electric	**$ 9,963**	**$ (2,864)**	**$ 7,099**
Gas	**4,093**	**(1,157)**	**2,936**
Transmission			
Electric	**12,571**	**(2,838)**	**9,733**
Gas	**1,954**	**(596)**	**1,358**
Generation	**6,079**	**(1,996)**	**4,083**
Other	**3,608**	**(1,130)**	**2,478**
Assets under construction	**1,717**	**–**	**1,717**
Land	**264**	**–**	**264**
	$ 40,249	**$ (10,581)**	**$ 29,668**

2016

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 9,616	$ (2,752)	$ 6,864
Gas	3,956	(1,096)	2,860
Transmission			
Electric	12,616	(2,876)	9,740
Gas	1,776	(562)	1,214
Generation	6,884	(2,474)	4,410
Other	3,497	(1,096)	2,401
Assets under construction	1,559	–	1,559
Land	289	–	289
	$ 40,193	$ (10,856)	$ 29,337

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

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

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

Other assets include buildings, equipment, vehicles, inventory, information technology assets and the Aitken Creek natural gas storage facility (Note 25).

10. PROPERTY, PLANT AND EQUIPMENT (cont'd)

As at December 31, 2017, assets under construction were primarily associated with FortisBC Energy's Tilbury liquefied natural gas facility expansion and ongoing transmission projects at ITC to upgrade or replace existing transmission assets to improve system reliability and transmission infrastructure to support generator interconnections and investments that provide regional benefits, such as the Multi-Value Projects.

The cost of property, plant and equipment under capital lease as at December 31, 2017 was $423 million (December 31, 2016 – $539 million) and related accumulated depreciation was $176 million (December 31, 2016 – $231 million).

Jointly Owned Facilities

UNS Energy and ITC hold undivided interests in jointly owned generating facilities and transmission systems, are entitled to their pro rata share of the property, plant and equipment, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2017, interests in jointly owned facilities consisted of the following.

(in millions, except as noted)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
San Juan Unit 1	50.0	**$ 351**	**$ (104)**	**$ 247**
Four Corners Units 4 and 5	7.0	**210**	**(98)**	**112**
Luna Energy Facility	33.3	**69**	**(4)**	**65**
Gila River Common Facilities	25.0	**41**	**(14)**	**27**
Springerville Coal Handling Facilities	83.0	**253**	**(102)**	**151**
Transmission Facilities	1.0–80.0	**854**	**(302)**	**552**
		$ 1,778	**$ (624)**	**$ 1,154**

11. INTANGIBLE ASSETS

2017

(in millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
Computer software	**$ 784**	**$ (474)**	**$ 310**
Land, transmission and water rights	**743**	**(103)**	**640**
Other	**117**	**(49)**	**68**
Assets under construction	**63**	**–**	**63**
	$ 1,707	**$ (626)**	**$ 1,081**

2016

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 748	$ (447)	$ 301
Land, transmission and water rights	700	(108)	592
Other	128	(56)	72
Assets under construction	46	–	46
	$ 1,622	$ (611)	$ 1,011

Included in the cost of land, transmission and water rights as at December 31, 2017 was $150 million (December 31, 2016 – $138 million) not subject to amortization.

Amortization expense related to intangible assets was $97 million for 2017 (2016 – $79 million). Amortization is estimated to average approximately $108 million annually for each of the next five years.

12. GOODWILL

(in millions)	2017	2016
Balance, beginning of year	$ 12,364	$ 4,173
Acquisition of ITC *(Note 25)*	(6)	8,106
Acquisition of Aitken Creek *(Note 25)*	–	27
Foreign currency translation impacts	(714)	58
Balance, end of year	$ 11,644	$ 12,364

Goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the functional currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

In September 2017 the Turks and Caicos Islands were struck by Hurricane Irma, resulting in significant damage to Fortis Turks and Caicos' transmission and distribution systems. The Turks and Caicos Islands are still in the process of recovering from the hurricane impact but are resuming normal business operations. The annual goodwill impairment test performed at October 1, 2017 included an assessment of the impact of Hurricane Irma and has concluded that there is no impairment to goodwill.

In December 2017 U.S. Tax Reform was enacted into law, passing significant changes to tax legislation in the United States. The goodwill impairment test considered the impact of U.S. Tax Reform and has confirmed that there is no impairment to goodwill.

There were no other events or circumstances in 2017 which required the Corporation to perform an impairment test of goodwill.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)	2017	2016
Trade accounts payable	$ 696	$ 554
Interest payable	223	218
Customer and other deposits	204	287
Dividends payable	185	166
Employee compensation and benefits payable	184	178
Accrued taxes other than income taxes	178	168
Gas and fuel cost payable	146	175
Fair value of derivative instruments *(Note 28)*	71	28
MGP site remediation *(Notes 8 (ix) and 16)*	35	21
Defined benefit pension and OPEB liabilities *(Note 24)*	22	26
Other	109	149
	$ 2,053	$ 1,970

14. LONG-TERM DEBT

(in millions)	Maturity Date	2017	2016
Regulated Utilities			
ITC			
Secured US First Mortgage Bonds – 4.67% weighted average fixed rate (2016 – 4.81%)	2018 – 2055	**$ 2,063**	$ 1,994
Secured US Senior Notes – 4.19% weighted average fixed rate (2016 – 4.19%)	2040 – 2046	**596**	638
Unsecured US Senior Notes – 3.98% weighted average fixed rate (2016 – 4.80%)	2020 – 2043	**3,618**	3,160
Unsecured US Shareholder Note – 6.00% fixed rate (2016 – 6.00%)	2028	**250**	267
Unsecured US Term Loan Credit Agreement – 2.03% weighted average variable rate	2019	**63**	–
UNS Energy			
Unsecured US Tax-Exempt Bonds – 4.04% weighted average fixed and variable rate (2016 – 3.87%)	2020 – 2040	**773**	827
Unsecured US Fixed Rate Notes – 4.26% weighted average fixed rate (2016 – 4.26%)	2021 – 2045	**1,411**	1,511
Central Hudson			
Unsecured US Promissory Notes – 4.28% weighted average fixed and variable rate (2016 – 4.25%)	2018 – 2057	**770**	768
FortisBC Energy			
Unsecured Debentures – 5.13% weighted average fixed rate (2016 – 5.24%)	2026 – 2047	**2,395**	2,220
FortisAlberta			
Unsecured Debentures – 4.70% weighted average fixed rate (2016 – 4.82%)	2024 – 2052	**2,035**	1,834
FortisBC Electric			
Secured Debentures – 8.80% fixed rate (2016 – 8.80%)	2023	**25**	25
Unsecured Debentures – 5.05% weighted average fixed rate (2016 – 5.22%)	2021 – 2050	**710**	635
Eastern Canadian			
Secured First Mortgage Sinking Fund Bonds – 6.14% weighted average fixed rate (2016 – 6.48%)	2020 – 2057	**585**	516
Secured First Mortgage Bonds – 6.19% weighted average fixed rate (2016 – 6.19%)	2018 – 2061	**195**	195
Unsecured Senior Notes – 6.11% weighted average fixed rate (2016 – 6.11%)	2018 – 2041	**104**	104
Caribbean Electric			
Unsecured US Senior Loan Notes and Bonds – 4.80% weighted average fixed and variable rate (2016 – 4.92%)	2018 – 2048	**525**	499
Corporate			
Unsecured US Senior Notes and Promissory Notes – 3.41% weighted average fixed rate (2016 – 3.43%)	2019 – 2044	**4,046**	4,353
Unsecured Debentures – 6.50% weighted average fixed rate (2016 – 6.50%)	2039	**200**	200
Unsecured Senior Notes – 2.85% fixed rate (2016 – 2.85%)	2023	**500**	500
Long-term classification of credit facility borrowings		**671**	973
Total long-term debt *(Note 28)*		**21,535**	21,219
Less: Deferred financing costs and debt discounts		**(139)**	(151)
Less: Current installments of long-term debt		**(705)**	(251)
		$ 20,691	$ 20,817

Certain long-term debt instruments at the Corporation's regulated utilities are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the Company to which the long-term debt is associated.

Covenants

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

Regulated Utilities

The majority of the long-term debt instruments at the Corporation's regulated utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

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

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

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

In August 2017 Central Hudson issued 30-year US$30 million unsecured notes at 4.05% and 40-year US$30 million unsecured notes at 4.20%. The net proceeds from the issuances were used to repay long-term debt and for general corporate purposes.

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

In October 2017 FortisBC Energy issued 30-year $175 million unsecured debentures at 3.69%. The net proceeds from the issuance were used to repay short-term borrowings and to finance capital expenditures.

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

Corporate

The unsecured debentures and senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

Credit Facilities

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

Notes to Consolidated Financial Statements

For the years ended December 31, 2017 and 2016

14. LONG-TERM DEBT (cont'd)

Credit Facilities (cont'd)

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

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

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

(2) The weighted average interest rate on short-term borrowings was approximately 1.8% as at December 31, 2017 (December 31, 2016 – 1.7%).

(3) As at December 31, 2017, credit facility borrowings classified as long-term debt included $312 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2016 – $61 million). The weighted average interest rate on credit facility borrowings classified as long term debt was approximately 2.5% as at December 31, 2017 (December 31, 2016 – 1.8%).

As at December 31, 2017 and 2016, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

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

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

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

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

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

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

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2022, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $40 million unsecured committed revolving credit facility, maturing in June 2020.

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

Corporate and Other

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

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

Repayment of Long-Term Debt

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

Year	Regulated Utilities (in millions)	Corporate and Other (in millions)	Total (in millions)
2018	$ 499	$ 206	$ 705
2019	169	113	282
2020	516	157	673
2021	435	784	1,219
2022	1,060	–	1,060
Thereafter	13,904	3,692	17,596
	$ 16,583	$ 4,952	$ 21,535

15. CAPITAL LEASE AND FINANCE OBLIGATIONS

Capital Lease Obligations

UNS Energy

TEP is party to three Springerville Common Facilities leases: (i) one lease with a fixed purchase price of US$38 million and an initial term to December 2017; and (ii) two leases with a fixed purchase price of US$68 million and an initial term to January 2021. In December 2017 TEP purchased a 17.8% undivided interest in the Springerville Common Facilities for $49 million bringing its total ownership of the assets to 67.8%. Upon purchase of the leased interest, current lease obligations on the consolidated balance sheet was reduced by $46 million. Under the remaining two leases, TEP has the option to renew the leases for periods of two or more years or exercise the purchase options under these contracts. In addition, TEP has entered into agreements with third parties that if the Springerville Common Facilities leases are not renewed, TEP will exercise the purchase options under these contracts. The third parties would be obligated to buy a portion of these facilities or continue to make payments to TEP for the use of these facilities.

TEP entered into an interest rate swap that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease obligation. As at December 31, 2017, interest on the lease obligation is payable at a six-month LIBOR plus a spread of 1.88% (December 31, 2016 – 1.88%). The swap has the effect of fixing the interest rate on a portion of the amortizing principal balance of $23 million (December 31, 2016 – $31 million). The interest rate swap expires in 2020 and is recorded as a cash flow hedge (Note 28).

The Springerville Common Facilities capital lease obligation bears interest at a rate of 5.08%. For 2017 $4 million (2016 – $4 million) of interest expense and $8 million (2016 – $7 million) of depreciation expense was recognized related to the Springerville capital lease obligations.

FortisBC Electric

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant hydroelectric plant ("Brilliant Plant") located in British Columbia. FortisBC Electric operates and maintains the Brilliant Plant, under the BPPA which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Approximately 94% of the output from the Brilliant Plant is being purchased by FortisBC Electric through the BPPA. The BPPA capital lease obligation bears interest at a composite rate of 5.00%. Included in energy supply costs for 2017 was $27 million (2016 – $27 million) recognized in accordance with the BPPA, as approved by the BCUC.

FortisBC Electric also has a capital lease obligation with respect to the operation of the Brilliant Terminal Station ("BTS"), under an agreement which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 9.00%. Included in operating expenses for 2017 was $3 million (2016 – $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC.

Finance Obligations

Between 2000 and 2005 FortisBC Energy entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FortisBC Energy. The natural gas distribution assets are considered to be integral equipment to real estate assets and, as such, the transactions have been accounted for as finance transactions. The proceeds from these transactions have been recognized as finance obligations on the consolidated balance sheet. Lease payments, net of the portion considered to be interest expense, reduce the finance obligations.

15. CAPITAL LEASE AND FINANCE OBLIGATIONS (cont'd)

Finance Obligations (cont'd)

Obligations under the above-noted lease-in lease-out transactions have implicit interest at rates ranging from 6.86% to 8.46% and are being repaid over an initial 35-year period. Each of the lease-in lease-out arrangements allows FortisBC Energy, at its option, to terminate the lease arrangement early, after 17 years. If the Company exercises this option, FortisBC Energy would pay the municipality an early termination payment which is equal to the carrying value of the obligation at that point in time. One of the early termination payments could potentially be due in 2018; however, the decision to early terminate has not yet been made by FortisBC Energy. This early termination payment has been included as due within one year in contractual obligations and has been recognized in current liabilities as at December 31, 2017.

Repayment of Capital Lease and Finance Obligations

The present value of the minimum lease payments required for the capital lease and finance obligations over the next five years and thereafter is as follows.

Year	Capital Leases *(in millions)*	Finance Obligations *(in millions)*	Total *(in millions)*
2018	$ 58	$ 32	$ 90
2019	59	15	74
2020	68	5	73
2021	46	32	78
2022	46	3	49
Thereafter	1,950	–	1,950
	$ 2,227	$ 87	$ 2,314
Less: Amounts representing imputed interest and executory costs on capital lease and finance obligations			(1,853)
Total capital lease and finance obligations			461
Less: Current installments			(47)
			$ 414

16. OTHER LIABILITIES

(in millions)	**2017**	2016
Defined benefit pension plan liabilities *(Note 24)*	**$ 393**	$ 410
OPEB plan liabilities *(Note 24)*	**381**	411
Asset retirement obligations	**71**	58
Customer and other deposits	**67**	69
Waneta Partnership promissory note *(Notes 28, 29 and 30)*	**63**	59
Mine reclamation and retiree health care liabilities	**40**	40
DSU, PSU and RSU liabilities *(Note 21)*	**39**	24
Fair value of derivative instruments *(Note 28)*	**37**	10
MGP site remediation *(Notes 8 (ix) and 13)*	**34**	77
Deferred compensation plan liabilities *(Note 9)*	**28**	27
Other	**57**	94
	$ 1,210	$ 1,279

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2017, its discounted net present value was $63 million (December 31, 2016 – $59 million). The promissory note is payable on April 1, 2020, the fifth anniversary of the commercial operation date of the Waneta Expansion.

TEP pays ongoing reclamation costs related to three coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP's share of the reclamation costs is expected to be US$61 million (December 31, 2016 – US$61 million) upon expiry of the coal agreements, which expire between 2019 and 2031. The mine reclamation liability recognized as at December 31, 2017 was $43 million (US$34 million) (December 31, 2016 – $35 million (US$25 million)), which represents the present value of the estimated future liability. TEP is permitted to recover these costs from customers and, accordingly, these costs are deferred and included in other regulatory assets.

Central Hudson has been notified by the New York State Department of Environmental Conservation to investigate MGPs at sites that the Company or its predecessors once owned and/or operated and, if necessary, remediate these sites. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2017, an obligation of $69 million (US$55 million) was recognized, including a current portion of $35 million (US$28 million) included in accounts payable and other current liabilities. Central Hudson has notified its insurers and intends to seek reimbursement, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances (Note 8 *(ix)*).

Other liabilities primarily include long-term accrued liabilities, deferred lease revenue, funds received in advance of expenditures and unrecognized tax benefits.

17. EARNINGS PER COMMON SHARE

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

	2017			2016		
	Net Earnings to Common Shareholders ***($ millions)***	**Weighted Average Shares** ***(# millions)***	**EPS**	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS
Basic EPS	**$ 963**	**415.5**	**$ 2.32**	$ 585	308.9	$ 1.89
Effect of potential dilutive securities:						
Stock Options	**–**	**0.7**		–	0.7	
Preference Shares	**–**	**–**		7	3.8	
Diluted EPS	**$ 963**	**416.2**	**$ 2.31**	$ 592	313.4	$ 1.89

18. PREFERENCE SHARES

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value
(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding	**2017**		2016	
First Preference Shares	**Number of Shares** ***(in thousands)***	**Amount** ***(in millions)***	Number of Shares *(in thousands)*	Amount *(in millions)*
Series F	**5,000**	**$ 122**	5,000	$ 122
Series G	**9,200**	**225**	9,200	225
Series H	**7,025**	**172**	7,025	172
Series I	**2,975**	**73**	2,975	73
Series J	**8,000**	**196**	8,000	196
Series K	**10,000**	**244**	10,000	244
Series M	**24,000**	**591**	24,000	591
	66,200	**$ 1,623**	66,200	$ 1,623

In September 2016 the Corporation redeemed all of the issued and outstanding $200 million 4.9% First Preference Shares, Series E at a redemption price of $25.3063 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share. Upon redemption, approximately $3 million of after-tax issuance costs associated with the First Preference Shares, Series E were recognized in net earnings attributable to preference equity shareholders.

18. PREFERENCE SHARES (cont'd)

Characteristics of the First Preference Shares are as follows.

First Preference Shares [1] [2]	Initial Yield (%)	Annual Dividend ($)	Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a One for One Basis
Perpetual fixed rate						
Series F	4.90	1.2250	–	December 1, 2011	25.00	–
Series J [3]	4.75	1.1875	–	December 1, 2017	26.00	–
Fixed rate reset [4] [5]						
Series G	5.25	0.9708	2.13	September 1, 2013	25.00	–
Series H	4.25	0.6250	1.45	June 1, 2015	25.00	Series I
Series K	4.00	1.0000	2.05	March 1, 2019	25.00	Series L
Series M	4.10	1.0250	2.48	December 1, 2019	25.00	Series N
Floating rate reset [5] [6]						
Series I [3]	2.10	–	1.45	June 1, 2015	25.50	Series H
Series L	–	–	2.05	March 1, 2024	–	Series K
Series N	–	–	2.48	December 1, 2024	–	Series M

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

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

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

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

(5) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their Shares into an equal number of Cumulative Redeemable First Preference Shares of a specified series.

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

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

19. ACCUMULATED OTHER COMPREHENSIVE INCOME

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive income by category is provided as follows.

	2017		
(in millions)	**Opening balance January 1**	**Net Change**	**Ending balance December 31**
Net unrealized foreign currency translation gains (losses):			
Unrealized foreign currency translation gains (losses) on net investments in foreign operations	**$ 1,227**	**$ (980)**	**$ 247**
(Losses) gains on hedges of net investments in foreign operations	**(472)**	**300**	**(172)**
Income tax recovery (expense)	**1**	**(2)**	**(1)**
	756	**(682)**	**74**
Cash flow hedges: *(Note 28)*			
Net change in fair value of cash flow hedges	**8**	**(2)**	**6**
Reclassification of cash flow hedges to finance charges	**–**	**4**	**4**
Income tax expense	**(3)**	**–**	**(3)**
	5	**2**	**7**
Unrealized employee future benefits (losses) gains: *(Note 24)*			
Unamortized net actuarial losses	**(19)**	**(3)**	**(22)**
Unamortized past service costs	**(3)**	**(1)**	**(4)**
Income tax recovery	**6**	**–**	**6**
	(16)	**(4)**	**(20)**
Accumulated other comprehensive income	**$ 745**	**$ (684)**	**$ 61**

	2016		
(in millions)	Opening balance January 1	Net Change	Ending balance December 31
Net unrealized foreign currency translation gains (losses):			
Unrealized foreign currency translation gains (losses) on net investments in foreign operations	$ 1,281	$ (54)	$ 1,227
(Losses) gains on hedges of net investments in foreign operations	(476)	4	(472)
Income tax recovery	1	–	1
	806	(50)	756
Available-for-sale investment:			
Realized gain on available-for-sale investment	(2)	2	–
Cash flow hedges: *(Note 28)*			
Net change in fair value of cash flow hedges	3	5	8
Income tax expense	(1)	(2)	(3)
	2	3	5
Unrealized employee future benefits (losses) gains: *(Note 24)*			
Unamortized net actuarial (losses) gains	(20)	1	(19)
Unamortized past service costs	(1)	(2)	(3)
Income tax recovery	6	–	6
	(15)	(1)	(16)
Accumulated other comprehensive income	$ 791	$ (46)	$ 745

20. NON-CONTROLLING INTERESTS

(in millions)	**2017**	2016
ITC	**$ 1,290**	$ 1,385
Waneta Partnership	**322**	330
Caribbean Utilities	**118**	122
Other	**16**	16
	$ 1,746	$ 1,853

21. STOCK-BASED COMPENSATION PLANS

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2017, the Corporation had the following stock option plans: the 2012 Plan and the 2006 Plan. The 2012 Plan was approved at the May 4, 2012 Annual General Meeting and will ultimately replace the 2006 Plan. The 2006 Plan will cease to exist when all outstanding options are exercised or expire in or before 2018. The former 2002 plan expired in February 2016. The Corporation has ceased the granting of options under the 2006 Plan and all new options granted after 2011 are being made under the 2012 Plan.

Options granted under the 2006 Plan are exercisable for a period not to exceed seven years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

Options granted under the 2012 Plan are exercisable for a period not to exceed ten years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

The following options were granted in 2017 and 2016. The accounting fair values of the options were estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions.

	2017	2016
Options granted *(#)*	**774,924**	788,188
Exercise price *($)* [(1)]	**42.36**	37.30
Grant date fair value *($)*	**3.22**	2.41
Assumptions:		
Dividend yield *(%)* [(2)]	**3.8**	3.9
Expected volatility *(%)* [(3)]	**16.1**	16.4
Risk-free interest rate *(%)* [(4)]	**1.2**	0.7
Weighted average expected life *(years)* [(5)]	**5.6**	5.5

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

The Corporation records compensation expense upon the issuance of stock options. Using the fair value method, each grant is treated as a single award, the fair value of which is amortized to compensation expense evenly over the four-year vesting period of the options.

The following table summarizes information related to stock options for 2017.

	Total Options		Non-vested Options [(1)]	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Grant Date Fair Value
Options outstanding, January 1, 2017	**4,160,192**	**$ 34.45**	**1,815,018**	**$ 2.78**
Granted	**774,924**	**$ 42.36**	**774,924**	**$ 3.22**
Exercised	**(1,217,029)**	**$ 32.73**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(761,830)**	**$ 3.03**
Cancelled/Forfeited	**(15,793)**	**$ 40.27**	**(15,793)**	**$ 2.88**
Options outstanding, December 31, 2017	**3,702,294**	**$ 36.65**	**1,812,319**	**$ 2.86**
Options vested, December 31, 2017 [(2)]	**1,889,975**	**$ 34.25**		

(1) As at December 31, 2017, there was $5 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.

(2) As at December 31, 2017, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $22 million.

The following table summarizes additional 2017 and 2016 stock option information.

(in millions)	**2017**	2016
Stock option expense recognized	**$ 3**	$ 2
Stock options exercised:		
Cash received for exercise price	**40**	28
Intrinsic value realized by employees	**15**	15
Fair value of options that vested	**2**	3

Directors' DSU Plan

Under the Corporation's Directors' DSU Plan, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation. In addition, directors can elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors. The DSUs are fully vested at the date of grant.

Number of DSUs	**2017**	2016
DSUs outstanding, beginning of year	**199,411**	167,762
Granted	**31,453**	30,165
Granted – notional dividends reinvested	**7,294**	6,994
DSUs paid out	**(53,363)**	(5,510)
DSUs outstanding, end of year	**184,795**	199,411

For 2017 expense of $3 million (2016 – $2 million) was recognized in earnings with respect to the DSU Plan.

In 2017, 53,363 DSUs were paid out to retired directors at a weighted average price of $45.37 per DSU for a total of approximately $2 million.

As at December 31, 2017, the liability related to outstanding DSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2017 of $46.01, for a total of $9 million (December 31, 2016 – $8 million), and is included in long-term other liabilities (Note 16).

21. STOCK-BASED COMPENSATION PLANS (cont'd)

PSU Plans

The Corporation's PSU Plans represent a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries, with the exception of ITC where PSUs were granted to all employees consistent with past practice. As at December 31, 2017, the Corporation had the 2015 PSU Plan and subsidiaries of the Corporation have adopted similar share unit plans that are modelled after the Corporation's plan. The former 2013 PSU Plan expired in 2017 when all outstanding PSUs were paid. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

The PSUs are subject to a three-year vesting and performance period, at which time a cash payment may be made, as determined by the Human Resources Committee of the Board of Directors. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the VWAP of the Corporation's common shares for the five trading days prior to the maturity of the grant and by a payout percentage that may range from 0% to 200%.

The payout percentage for the PSU Plans is based on the Corporation's performance over the three-year period, mainly determined by: (i) the Corporation's total shareholder return as compared to a pre-defined peer group of companies; and (ii) the Corporation's cumulative earnings per common share, or for certain subsidiaries the Company's cumulative net income, as compared to the target established at the time of the grant. As at December 31, 2017, the estimated weighted average payout percentages for the grants under the 2015 PSU Plan range from 82% to 113%.

The following table summarizes information related to the PSUs for 2017 and 2016.

Number of PSUs	2017	2016
PSUs outstanding, beginning of year	**931,951**	694,386
Granted	**711,749**	351,737
Granted – notional dividends reinvested	**44,893**	34,439
PSUs paid out	**(239,509)**	(148,168)
PSUs cancelled/forfeited	**(16,910)**	(443)
Transferred to RSU Plan	**(81,214)**	–
PSUs outstanding, end of year	**1,350,960**	931,951

In 2017, 239,509 PSUs were paid out at $41.46 per PSU, for a total of approximately $11 million. The payout was made in respect of the PSUs granted in 2014 under the former 2013 PSU Plan. The PSU payout percentage was 113% based on the Corporation's and subsidiaries' performance over the three-year period, as determined by the respective Human Resources Committee.

For 2017 expense of approximately $26 million (2016 – $16 million) was recognized in earnings with respect to the PSU Plans and there was $17 million of unrecognized compensation expense related to PSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2017, the aggregate intrinsic value of the outstanding PSUs was $58 million, with a weighted average contractual life of approximately one year. The liability related to outstanding PSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2017 of $46.01, for a total of $41 million (December 31, 2016 – $30 million), and is included in accounts payable and other current liabilities and long-term other liabilities (Notes 13 and 16).

RSU Plans

The Corporation's 2015 RSU Plan represents a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries, with the exception of ITC where RSUs were granted to all employees consistent with past practice. Each RSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period, at which time a cash payment may be made. Each RSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of RSUs	2017	2016
RSUs outstanding, beginning of year	123,612	58,740
Granted	349,496	70,393
Granted – notional dividends reinvested	15,407	4,709
RSUs paid out	(74,876)	(10,201)
RSUs cancelled/forfeited	(12,090)	(29)
Transferred from PSU Plan	81,214	–
RSUs outstanding, end of year	482,763	123,612

In 2017, 74,876 RSUs were paid out at a weighted average price of $43.42 per RSU, for a total of approximately $3 million. In accordance with the respective RSU plans, the RSUs were paid to senior management upon retirement or death.

For 2017 expense of approximately $8 million (2016 – $2 million) was recognized in earnings with respect to the RSU Plan and there was approximately $11 million of unrecognized compensation expense related to RSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2017, the aggregate intrinsic value of the outstanding RSUs was $22 million, with a weighted average contractual life of approximately two years. The liability related to outstanding RSUs was recorded at the VWAP of the Corporation's common shares for the last five trading days of 2017 of $46.01, for a total of $11 million (December 31, 2016 – $3 million), and is included in accounts payable and other current liabilities and long-term other liabilities (Notes 13 and 16).

22. OTHER INCOME, NET

(in millions)	2017	2016
Equity component of AFUDC	$ 74	$ 37
Net foreign exchange gain [1]	26	–
Interest income	14	7
Equity income – Belize Electricity	4	7
Other	9	2
	$ 127	$ 53

[1] The net foreign exchange gain includes a one-time $21 million unrealized foreign exchange gain on US dollar-denominated affiliate loan.

23. INCOME TAXES

U.S. Tax Reform

On December 22, 2017, the *Tax Cuts and Jobs Act* was signed into law by the President of the United States of America, enacting significant changes to tax legislation, including a reduction in the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018. The Corporation's U.S. utilities and holding companies were required to remeasure their deferred tax assets and liabilities at the new corporate income tax rate as at the date of enactment. The one-time remeasurement resulted in a net decrease in deferred income tax liabilities of $1.3 billion, the recognition of a regulatory liability of $1.5 billion for the reduction in deferred income tax expected to be refunded to customers, and an unfavourable earnings impact of $168 million recognized in deferred income tax expense ($146 million after non-controlling interest).

Fortis is still evaluating the bonus depreciation exemption for its U.S. regulated utilities and anticipates further clarification. The Corporation's U.S. regulated utilities have recorded an estimated provision for bonus depreciation for property, plant and equipment in service between September 27, 2017 and December 31, 2017, which impacts the tax loss carryforward deferred tax asset and property, plant and equipment deferred tax liability.

23. INCOME TAXES (cont'd)

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. The significant components of deferred income tax assets and liabilities consist of the following.

(in millions)	2017	2016
Gross deferred income tax assets		
Tax loss and credit carryforwards	**$ 571**	$ 675
Regulatory liabilities	**596**	292
Employee future benefits	**143**	155
Fair value of long-term debt adjustment	**43**	88
Unrealized foreign exchange losses on long-term debt	**28**	56
Other	**8**	57
	1,389	1,323
Deferred income tax assets valuation allowance	**(44)**	(56)
Net deferred income tax assets	**$ 1,345**	$ 1,267
Gross deferred income tax liabilities		
Property, plant and equipment	**$ (3,353)**	$ (4,213)
Regulatory assets	**(203)**	(242)
Intangible assets	**(87)**	(75)
	(3,643)	(4,530)
Net deferred income tax liability	**$ (2,298)**	$ (3,263)

The deferred income tax assets associated with unrealized foreign exchange losses on long-term debt and tax loss and credit carryforwards reflects $44 million of unrealized and realized capital losses as at December 31, 2017 (December 31, 2016 – $56 million). The deferred income tax asset can only be used if the Corporation has capital gains to offset the losses once realized. Management believes that it is more likely than not that Fortis will not be able to generate future capital gains and, as a result, the Corporation recorded a $44 million valuation allowance against the deferred income tax asset as at December 31, 2017 (December 31, 2016 – $56 million). Management believes that based on its historical pattern of taxable income, Fortis will produce sufficient income in the future to realize all other deferred income tax assets.

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2017 and 2016.

(in millions)	2017	2016
Total unrecognized tax benefits, beginning of year	**$ 23**	$ 13
Additions related to the current year	**13**	10
Adjustments related to prior years and U.S. Tax Reform	**(8)**	–
Total unrecognized tax benefits, end of year	**$ 28**	$ 23

Unrecognized tax benefits, if recognized, would reduce income tax expense by $2 million in 2017. Fortis has not recognized interest expense in 2017 and 2016 related to unrecognized tax benefits.

The components of the income tax expense were as follows.

(in millions)	2017	2016
Canadian		
Earnings before income taxes	**$ 461**	$ 357
Current income taxes	**41**	66
Deferred income taxes	**16**	(23)
Total Canadian	**$ 57**	$ 43
Foreign		
Earnings before income taxes	**$ 1,252**	$ 501
Current income taxes	**3**	(19)
Deferred income taxes	**528**	121
Total Foreign	**$ 531**	$ 102
Income tax expense	**$ 588**	$ 145

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

(in millions, except as noted)	2017	2016
Earnings before income taxes	**$ 1,713**	$ 858
Combined Canadian federal and provincial statutory income tax rate	**28.0%**	28.0%
Expected federal and provincial taxes at statutory rate	**$ 480**	$ 240
Increase (decrease) resulting from:		
Enactment of U.S. Tax Reform	**168**	–
Foreign and other statutory rate differentials	**31**	(28)
Allowance for funds used during construction	**(26)**	(14)
Effects of rate-regulated accounting:		
Difference between depreciation claimed for income tax and accounting purposes	**(26)**	(25)
Items capitalized for accounting purposes but expensed for income tax purposes	**(21)**	(26)
Release of valuation allowance and non-taxable portion of gain on dispositions	**(17)**	–
Other	**(1)**	(2)
Income tax expense	**$ 588**	$ 145
Effective tax rate	**34.3%**	16.9%

As at December 31, 2017, the Corporation had the following tax carryforward amounts.

(in millions)	Expiring Year	2017
Canadian		
Capital loss	n/a	**$ 70**
Non-capital loss	2025 – 2037	**326**
Other tax credits	2026 – 2037	**2**
		398
Unrecognized in the consolidated financial statements		**(65)**
		$ 333
Foreign		
Capital loss	2018	**$ 1**
Federal and state net operating loss	2022 – 2037	**1,850**
Other tax credits	2021 – 2037	**126**
		1,977
Unrecognized in the consolidated financial statements		**(1)**
		$ 1,976
Total tax carryforwards		**$ 2,309**

23. *INCOME TAXES (cont'd)*

As at December 31, 2017, the Corporation had approximately $2,309 million in tax carryforward amounts recognized in the consolidated financial statements (December 31, 2016 – $1,235 million).

The Corporation and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal and British Columbia). The Corporation's 2012 to 2017 taxation years are still open for audit in the Canadian jurisdictions and 2013 to 2017 taxation years are still open for audit in the United States jurisdictions.

24. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, OPEB plans, and defined contribution pension plans. For the defined benefit pension and OPEB plan arrangements, the benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year.

Actuarial valuations are required to determine funding contributions for pension plans, at least, every three years for Fortis' Canadian and Caribbean subsidiaries. The most recent valuations were as of December 31, 2014 for Newfoundland Power, FortisOntario and the Corporation; December 31, 2015 for FortisAlberta and FortisBC Energy (plan covering non-unionized employees); and December 31, 2016 for FortisBC Electric, FortisBC Energy (plans covering unionized employees) and Caribbean Utilities.

ITC, UNS Energy and Central Hudson perform annual actuarial valuations, as their funding contribution requirements are based on maintaining annual target fund percentages. ITC, UNS Energy and Central Hudson have all met the minimum funding requirements.

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

The Corporation's consolidated defined benefit pension and OPEB plan weighted average asset allocations were as follows.

Plan assets as at December 31 *(%)*	**2017 Target Allocation**	**2017**	2016
Equities	**48**	**47**	50
Fixed income	**45**	**46**	45
Real estate	**6**	**6**	4
Cash and other	**1**	**1**	1
	100	**100**	100

The fair value measurements of defined benefit pension and OPEB plan assets by fair value hierarchy, as defined in Note 28, were as follows.

Fair value of plan assets as at December 31, 2017

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Equities	**$ 522**	**$ 949**	**$ –**	**$ 1,471**
Fixed income	**133**	**1,289**	**–**	**1,422**
Real estate	**–**	**13**	**168**	**181**
Private equities	**–**	**–**	**22**	**22**
Cash and other	**8**	**14**	**–**	**22**
	$ 663	**$ 2,265**	**$ 190**	**$ 3,118**

Fair value of plan assets as at December 31, 2016

(in millions)	Level 1	Level 2	Level 3	Total
Equities	$ 507	$ 942	$ –	$ 1,449
Fixed income	124	1,180	–	1,304
Real estate	–	13	103	116
Private equities	–	–	10	10
Cash and other	6	13	–	19
	$ 637	$ 2,148	$ 113	$ 2,898

Notes to Consolidated Financial Statements

The following table is a reconciliation of changes in the fair value of pension plan assets that have been measured using Level 3 inputs for the years ended December 31, 2017 and 2016.

(in millions)	**2017**	2016
Balance, beginning of year	**$ 113**	$ 107
Actual return on plan assets held at end of year	**12**	8
Foreign currency translation impacts	**(2)**	(1)
Purchases, sales and settlements	**67**	(1)
Balance, end of year	**$ 190**	$ 113

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension and OPEB plans and their respective funded status.

	Defined Benefit Pension Plans		**OPEB Plans**	
(in millions)	**2017**	2016	**2017**	2016
Change in benefit obligation [(1)]				
Balance, beginning of year	**$ 3,037**	$ 2,828	**$ 676**	$ 574
Liabilities assumed on acquisition	**–**	167	**–**	111
Service costs	**76**	66	**27**	18
Employee contributions	**16**	17	**2**	2
Interest costs	**115**	112	**25**	23
Benefits paid	**(133)**	(119)	**(22)**	(23)
Actuarial losses (gains)	**217**	45	**(14)**	(1)
Past service credits/plan amendments	**–**	(10)	**(3)**	–
Foreign currency translation impacts	**(113)**	(69)	**(26)**	(28)
Balance, end of year [(2)]	**$ 3,215**	$ 3,037	**$ 665**	$ 676
Change in value of plan assets				
Balance, beginning of year	**$ 2,646**	$ 2,466	**$ 252**	$ 181
Assets assumed on acquisition	**–**	85	**–**	65
Actual return on plan assets	**336**	187	**37**	13
Benefits paid	**(127)**	(119)	**(22)**	(23)
Employee contributions	**16**	17	**2**	2
Employer contributions	**69**	47	**26**	18
Foreign currency translation impacts	**(99)**	(37)	**(18)**	(4)
Balance, end of year	**$ 2,841**	$ 2,646	**$ 277**	$ 252
Funded status	**$ (374)**	$ (391)	**$ (388)**	$ (424)

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

(2) The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $2,940 million as at December 31, 2017 (December 31, 2016 – $2,741 million).

24. EMPLOYEE FUTURE BENEFITS (cont'd)

The following table summarizes the employee future benefit assets and liabilities and their classifications on the consolidated balance sheet.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2017**	2016	**2017**	2016
Assets				
Defined benefit pension assets:				
Long-term *(Note 9)*	**$ 31**	$ 32	**$ –**	$ –
OPEB plan assets:				
Long-term *(Note 9)*	**–**	–	**3**	–
Liabilities				
Defined benefit pension liabilities:				
Current *(Note 13)*	**12**	13	**–**	–
Long-term *(Note 16)*	**393**	410	**–**	–
OPEB plan liabilities:				
Current *(Note 13)*	**–**	–	**10**	13
Long-term *(Note 16)*	**–**	–	**381**	411
Net liabilities	**$ 374**	$ 391	**$ 388**	$ 424

The net benefit cost for the Corporation's defined benefit pension plans and OPEB plans were as follows.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2017**	2016	**2017**	2016
Components of net benefit cost				
Service costs	**$ 76**	$ 66	**$ 27**	$ 18
Interest costs	**115**	112	**25**	23
Expected return on plan assets	**(151)**	(145)	**(14)**	(12)
Amortization of actuarial losses	**45**	48	**2**	2
Amortization of past service credits/plan amendments	**–**	1	**(12)**	(10)
Regulatory adjustments	**2**	6	**4**	9
Net benefit cost	**$ 87**	$ 88	**$ 32**	$ 30

The following table provides the components of accumulated other comprehensive loss and regulatory assets and liabilities, which would otherwise have been recognized as accumulated other comprehensive loss, for the years ended December 31, 2017 and 2016, which have not been recognized as components of net benefit cost.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2017**	2016	**2017**	2016
Unamortized net actuarial losses	**$ 22**	$ 19	**$ –**	$ –
Unamortized past service costs	**1**	1	**3**	2
Income tax recovery	**(5)**	(5)	**(1)**	(1)
Accumulated other comprehensive loss *(Note 19)*	**$ 18**	$ 15	**$ 2**	$ 1
Net actuarial losses	**$ 443**	$ 479	**$ 17**	$ 53
Past service credits	**(11)**	(11)	**(23)**	(31)
Amount deferred due to actions of regulators	**10**	12	**27**	32
	$ 442	$ 480	**$ 21**	$ 54
Regulatory assets *(Note 8 (ii))*	**$ 442**	$ 480	**$ 68**	$ 96
Regulatory liabilities *(Note 8 (ii))*	**–**	–	**(47)**	(42)
Net regulatory assets	**$ 442**	$ 480	**$ 21**	$ 54

Notes to Consolidated Financial Statements

The following table provides the components recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2017**	2016	**2017**	2016
Current year net actuarial losses (gains)	**$ 5**	$ 4	**$ (1)**	$ (2)
Past service costs/plan amendments	**–**	–	**2**	–
Amortization of actuarial losses	**(1)**	–	**–**	–
Foreign currency translation impacts	**(1)**	–	**–**	–
Income tax recovery	**–**	(1)	**–**	–
Total recognized in comprehensive income	**$ 3**	$ 3	**$ 1**	$ (2)
Assets assumed on acquisition	**$ –**	$ 23	**$ –**	$ 3
Current year net actuarial losses (gains)	**24**	(1)	**(35)**	–
Past service credits/plan amendments	**–**	(10)	**(5)**	–
Amortization of actuarial losses	**(44)**	(47)	**(1)**	(4)
Amortization of past service (costs) credits	**–**	(1)	**12**	13
Foreign currency translation impacts	**(17)**	(9)	**2**	1
Regulatory adjustments	**(1)**	(11)	**(6)**	(6)
Total recognized in regulatory assets	**$ (38)**	$ (56)	**$ (33)**	$ 7

Net actuarial losses of $1 million are expected to be amortized from accumulated other comprehensive income into net benefit cost in 2018 related to defined benefit pension plans.

Net actuarial losses of $46 million, past service credits of $1 million and regulatory adjustments of $1 million are expected to be amortized from regulatory assets into net benefit cost in 2018 related to defined benefit pension plans. Past service credits of $8 million and regulatory adjustments of $4 million are expected to be amortized from regulatory assets into net benefit cost in 2018 related to OPEB plans.

Significant weighted average assumptions	Defined Benefit Pension Plans		OPEB Plans	
(%)	**2017**	2016	**2017**	2016
Discount rate during the year [(1)]	**3.98**	4.08	**3.96**	4.14
Discount rate as at December 31	**3.58**	4.00	**3.59**	4.00
Expected long-term rate of return on plan assets [(2)]	**5.97**	6.25	**5.81**	6.25
Rate of compensation increase	**3.34**	3.36	**–**	–
Health care cost trend increase as at December 31 [(3)]	**–**	–	**4.71**	4.70

(1) ITC and UNS use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.

(2) Developed by management with assistance from external actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

(3) The projected 2018 weighted average health care cost trend rate is 6.38% for OPEB plans and is assumed to decrease over the next 11 years by 2028 to the weighted average ultimate health care cost trend rate of 4.71% and remain at that level thereafter.

For 2017 the effects of changing the health care cost trend rate by 1% were as follows.

(in millions)	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in accumulated benefit obligation	**$ 96**	**$ (74)**
Increase (decrease) in service and interest costs	**26**	**(19)**

24. *EMPLOYEE FUTURE BENEFITS (cont'd)*

The following table provides the amount of benefit payments expected to be made over the next 10 years.

Year	Defined Benefit Pension Payments *(in millions)*	OPEB Payments *(in millions)*
2018	$ 134	$ 23
2019	137	24
2020	142	25
2021	148	27
2022	156	29
2023 – 2027	860	160

During 2018 the Corporation expects to contribute $66 million for defined benefit pension plans and $36 million for OPEB plans.

In 2017 the Corporation expensed $38 million (2016 – $31 million) related to defined contribution pension plans.

25. BUSINESS ACQUISITIONS

2017

Terminated Acquisition of an Interest in Waneta Dam

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

2016

ITC

On October 14, 2016, Fortis and GIC acquired all of the outstanding common shares of ITC for an aggregate purchase price of approximately $15.7 billion (US$11.8 billion) on closing, including approximately $6.3 billion (US$4.8 billion) of ITC consolidated indebtedness. ITC is now a subsidiary of Fortis, with an affiliate of GIC owning a 19.9% minority interest in ITC.

Under the terms of the transaction, ITC shareholders received US$22.57 in cash and 0.7520 of a Fortis common share per ITC share, representing total consideration of approximately $9.4 billion (US$7.0 billion). The net cash consideration totalled approximately $4.7 billion (US$3.5 billion) and was financed using: (i) net proceeds from the issuance of US$2.0 billion ($2.6 billion) unsecured notes in October 2016; (ii) net proceeds from GIC's US$1.228 billion ($1.6 billion) minority investment, which includes a shareholder note of US$199 million ($263 million); and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility. On October 14, 2016, approximately 114.4 million common shares of Fortis were issued to shareholders of ITC, representing share consideration of approximately $4.7 billion (US$3.5 billion), based on the closing price for Fortis common shares of $40.96 and the closing foreign exchange rate of US$1.00=CAD$1.32 on October 13, 2016.

The following table summarizes the final allocation of the purchase consideration to the assets and liabilities acquired as at October 14, 2016 based on their fair values, using an exchange rate of US$1.00=CAD$1.32.

(in millions)	**Total**
Share consideration	$ 4,684
Cash consideration	4,658
Total consideration	$ 9,342
Purchase consideration for 80.1% of ITC common shares	$ 7,721
19.9% minority shareholder investment and shareholder note	1,621
	$ 9,342
Fair value assigned to net assets:	
Current assets	$ 319
Long-term regulatory assets	319
Property, plant and equipment	8,345
Intangible assets	399
Other long-term assets	71
Current liabilities	(625)
Assumed short-term borrowings	(311)
Assumed long-term debt (including current portion)	(6,006)
Long-term regulatory liabilities	(327)
Deferred income taxes	(910)
Other long-term liabilities	(166)
	1,108
Cash and cash equivalents	134
Fair value of net assets acquired	1,242
Goodwill *(Note 12)*	$ 8,100

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on October 14, 2016.

Acquisition-related expenses totalled approximately $118 million ($90 million after tax) in 2016. Acquisition-related expenses included: (i) investment banking, legal, consulting and other fees totalling approximately $79 million ($62 million after tax) in 2016, which were included in operating expenses; and (ii) fees associated with the Corporation's acquisition credit facilities and deal-contingent interest rate swap contracts totalling approximately $39 million ($28 million after tax) in 2016, which were included in finance charges. From the date of acquisition, ITC also recognized in 2016 $27 million in after-tax expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition, of which the Corporation's share was $22 million.

Pro Forma Data

The unaudited pro forma financial information below gives effect to the acquisition of ITC as if the transaction had occurred at the beginning of 2016. This pro forma data is presented for information purposes only, and does not necessarily represent the results that would have occurred had the acquisition taken place at the beginning of 2016, nor is it necessarily indicative of the results that may be expected in future periods.

(in millions)	2016
Pro forma revenue	$ 7,995
Pro forma net earnings attributable to common equity shareholders [(1)]	919

[(1)] Pro forma net earnings attributable to common equity shareholders exclude all after-tax acquisition-related expenses incurred by ITC and the Corporation. A pro forma adjustment has been made to net earnings for the year presented to reflect the Corporation's after-tax financing costs associated with the acquisition.

25. BUSINESS ACQUISITIONS (cont'd)

Aitken Creek

On April 1, 2016, Fortis acquired Aitken Creek Gas Storage ULC from Chevron Canada Properties Ltd. for approximately $349 million, plus the cost of working gas inventory. The net cash purchase price was initially financed through US dollar-denominated borrowings under the Corporation's committed revolving credit facility. In December 2015 the Corporation paid a deposit of $38 million as part of the purchase consideration for the transaction.

The allocation of purchase consideration to the assets and liabilities acquired as at April 1, 2016, based on their fair values, resulted in the recognition of approximately $27 million in goodwill, which was associated with deferred income tax liabilities. The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on April 1, 2016. The purchase price allocation was finalized during the first quarter of 2017.

26. DISPOSITIONS

Walden

In February 2016 FortisBC Electric sold the non-regulated Walden hydroelectric power plant assets for gross proceeds of approximately $9 million, and as a result recognized a gain on sale of less than $1 million, after tax and transaction costs.

27. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	**2017**	2016
Cash paid for:		
Interest	**$ 927**	$ 644
Income taxes	**69**	62
Change in working capital:		
Accounts receivable and other current assets	**$ (74)**	$ 43
Prepaid expenses	**(3)**	(4)
Inventories	**(6)**	17
Regulatory assets – current portion	**39**	(58)
Accounts payable and other current liabilities	**119**	25
Regulatory liabilities – current portion	**(172)**	(1)
	$ (97)	$ 22
Non-cash investing and financing activities:		
Common share dividends reinvested	**$ 253**	$ 162
Common shares issued on business acquisition *(Note 25)*	**–**	4,684
Additions to property, plant and equipment, and intangible assets included in current and long-term liabilities	**307**	296
Commitment to purchase capital lease interest	**–**	48
Transfer of deposit on business acquisition *(Note 25)*	**–**	38
Contributions in aid of construction	**35**	9
Exercise of stock options into common shares	**5**	4

28. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets;
Level 2: Fair value determined using pricing inputs that are observable; and
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant 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. Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one fair value to another. There were transfers between levels 2 and 3 during 2017.

The following tables present, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

As at December 31, 2017

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Energy contracts subject to regulatory deferral (1) (2)	**$ –**	**$ 19**	**$ 2**	**$ 21**
Energy contracts not subject to regulatory deferral (1)	**–**	**26**	**4**	**30**
Foreign exchange contracts (3)	**3**	**–**	**–**	**3**
Other investments (4)	**78**	**–**	**–**	**78**
Total assets	**$ 81**	**$ 45**	**$ 6**	**$ 132**
Liabilities				
Energy contracts subject to regulatory deferral (2) (5)	**$ (1)**	**$ (103)**	**$ (2)**	**$ (106)**
Energy contracts not subject to regulatory deferral (5)	**–**	**–**	**(1)**	**(1)**
Interest rate and total return swaps (3)	**–**	**(1)**	**–**	**(1)**
Total liabilities	**$ (1)**	**$ (104)**	**$ (3)**	**$ (108)**

As at December 31, 2016

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Energy contracts subject to regulatory deferral (1) (2)	$ 1	$ 13	$ 5	$ 19
Energy contracts not subject to regulatory deferral (1)	–	1	2	3
Interest rate swaps (3)	–	11	–	11
Other investments (4)	69	–	–	69
Total assets	$ 70	$ 25	$ 7	$ 102
Liabilities				
Energy contracts subject to regulatory deferral (2) (5)	$ –	$ (21)	$ (5)	$ (26)
Energy contracts not subject to regulatory deferral (5)	–	(9)	–	(9)
Interest rate and total return swaps (3)	–	(3)	–	(3)
Total liabilities	$ –	$ (33)	$ (5)	$ (38)

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

(2) Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

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

(4) Included in long-term other assets on the consolidated balance sheet (Note 9).

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

28. *FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)*

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 tables present the potential offset of counterparty netting.

As at December 31, 2017 *(in millions)*	**Gross Amount Recognized in Balance Sheet**	**Counterparty Netting of Energy Contracts**	**Cash Collateral Received/ Posted**	**Net Amount**
Derivative assets				
Energy contracts	**$ 51**	**$ 17**	**$ 7**	**$ 27**
Derivative liabilities				
Energy contracts	**(107)**	**(17)**	**–**	**(90)**

As at December 31, 2016 *(in millions)*	Gross Amount Recognized in Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Received/ Posted	Net Amount
Derivative assets				
Energy contracts	$ 22	$ 9	$ –	$ 13
Derivative liabilities				
Energy contracts	(35)	(9)	–	(26)

Derivative Instruments

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

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

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

FortisBC Energy holds gas supply contracts and fixed-price financial swaps to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on published market prices and forward curves for natural gas.

These energy contracts were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recognized in earnings. As at December 31, 2017, unrealized losses of $87 million (December 31, 2016 – $19 million) were recognized in regulatory assets and unrealized gains of $2 million were recognized in regulatory liabilities (December 31, 2016 – $12 million) (Note 8 *(viii)*).

Energy Contracts Not Subject to Regulatory Deferral

UNS Energy holds wholesale trading contracts that qualify as derivative instruments to fix power prices and realize potential margin, of which 10% of any realized gains are shared with customers through UNS Energy's rate stabilization accounts. The fair value of the wholesale contracts was measured using a market approach using independent third-party information, where possible.

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

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

Foreign Exchange Contracts

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

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

Interest Rate and Total Return Swaps

UNS Energy holds an interest rate swap to mitigate its exposure to volatility in variable interest rates on capital lease obligations (Note 15). The interest rate swap agreement expires in 2020 and has a notional amount of $23 million.

The Corporation holds three total return swaps to manage the cash flow risk associated with forecasted future cash settlements of the respective DSU and RSU obligations (Note 21). The total return swaps have a combined notional amount of $33 million and terms ranging from one to three years terminating in January 2018, 2019 and 2020.

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

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

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

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

Other Investments

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

28. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Level 3 Fair Value Measurement

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

The following table presents a reconciliation of changes in the fair value of net assets and liabilities classified as level 3 in the fair value hierarchy. Transfers from level 3 to level 2 principally resulted from management's decision that inputs used to calculate the fair value of derivatives are observable and level 2 classification is appropriate.

(in millions)	**2017**	2016
Balance, beginning of year	**$ 2**	$ (18)
Realized losses	**(10)**	(19)
Unrealized (losses) gains	**(3)**	12
Settlements	**12**	27
Transfers of assets out of level 3	**(2)**	–
Transfers of liabilities out of level 3	**4**	–
Balance, end of year	**$ 3**	$ 2

Volume of Derivative Activity

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

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

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

Credit Risk

For cash equivalents, accounts receivable and other current assets, and long-term other receivables, the Corporation's credit risk is generally limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as a result of approximately 69% of its revenue being derived from three primary customers. Credit risk is limited as such customers have investment-grade credit ratings. ITC further reduces its exposure to 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 a result of its distribution service billings being 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 and Aitken Creek may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Companies use netting arrangements to reduce credit risk and net settle payments with counterparties where net settlement provisions exist. They also limit credit risk by only dealing with counterparties that have investment-grade credit ratings. At UNS Energy and Central Hudson, contractual arrangements also contain certain provisions requiring counterparties to derivative instruments to post collateral under certain circumstances.

The value of all derivative instruments in net liability positions under contracts with credit risk-related contingent features was $57 million as of December 31, 2017 (December 31, 2016 – $37 million). If all the credit risk-related contingent features were triggered on December 31, 2017, the Corporation would have been required to post an additional $57 million of collateral to counterparties.

Foreign Exchange Hedge

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos 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 the above-noted 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 the Corporation's foreign subsidiaries' earnings.

As at December 31, 2017, the Corporation's corporately issued US$3,385 million (December 31, 2016 – US$3,511 million) long-term debt has been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2017, the Corporation had approximately US$7,548 million (December 31, 2016 – US$7,250 million) in foreign net investments that were unhedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded on the consolidated balance sheet in accumulated other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded on the consolidated balance sheet in accumulated other comprehensive income.

Financial Instruments Not Carried at Fair Value

The following table discloses the estimated fair value measurements of the Corporation's financial instruments not carried at fair value. The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

	2017		2016	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion *(Note 14)* [(1)]	**$ 21,535**	**$ 23,481**	$ 21,219	$ 22,523
Waneta Partnership promissory note *(Note 16)*	**63**	**64**	59	61

[(1)] Long-term debt is valued using Level 2 inputs.

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

29. VARIABLE INTEREST ENTITY

The Corporation's ownership interest in the Waneta Partnership is considered to be a variable interest entity ("VIE") based on an assessment of the rights of the limited partners and the general partner. It was determined under the VIE model that the Corporation is the primary beneficiary of the Waneta Partnership and should consolidate its investment. As the primary beneficiary, the Corporation has the power to direct the activities of the partnership and the obligation to absorb losses or the right to receive benefits that could potentially be significant to the partnership, as discussed below.

The purpose of the Waneta Partnership was to construct, own and operate the Waneta Expansion on the Pend d'Oreille River south of Trail, British Columbia, which was completed in April 2015. The Corporation has a 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. The general partner, which is owned by the Corporation and CPC/CBT in the same proportion as the Waneta Partnership, has a 0.01% interest in the Waneta Partnership. Each partner pays its proportionate share of the costs and is entitled to a proportionate share of the net revenue and expenses. The construction of the Waneta Expansion was financed and managed by the Corporation and CPC/CBT. The Waneta Expansion is operated and maintained by a wholly owned subsidiary of the Corporation and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts.

The following table details the Waneta Partnership assets, liabilities, revenue, expenses, and cash flow included in the Corporation's consolidated financial statements.

(in millions)	**2017**	2016
Assets		
Cash and cash equivalents	**$ 16**	$ 15
Accounts receivable and other current assets	**14**	14
Property, plant and equipment	**688**	696
Intangible assets	**30**	30
	$ 748	$ 755
Liabilities		
Accounts payable and other current liabilities	**$ (28)**	$ (3)
Other liabilities	**(63)**	(79)
	(91)	(82)
Net assets before partners' equity	**$ 657**	$ 673

(in millions)	**2017**	2016
Revenue	**$ 93**	$ 91
Expenses		
Operating expense	**17**	17
Depreciation and amortization	**18**	18
Finance charges	**4**	3
	39	38
Net earnings	**$ 54**	$ 53

Cash used in investing activities at the Waneta Partnership for 2017 included capital expenditures of $5 million (2016 – $18 million). Cash flow related to financing activities for 2017 included dividends paid by the Waneta Partnership to non-controlling interests of $34 million (2016 – $31 million).

30. COMMITMENTS AND CONTINGENCIES

As at December 31, 2017, the Corporation's consolidated commitments in each of the next five years and for periods thereafter, excluding repayments of long-term debt and capital lease and finance obligations separately disclosed in Notes 14 and 15, respectively, are as follows.

(in millions)	Total	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Interest obligations on long-term debt	**$ 14,575**	$ 892	$ 878	$ 858	$ 837	$ 792	$ 10,318
Power purchase obligations (1)	**2,240**	275	157	126	118	117	1,447
Renewable power purchase obligations (2)	**1,428**	93	92	92	92	91	968
Gas purchase obligations (3)	**1,085**	278	201	189	147	112	158
Long-term contracts – UNS Energy (4)	**910**	157	158	125	79	50	341
ITC easement agreement (5)	**413**	13	13	13	13	13	348
Renewable energy credit purchase agreements (6)	**125**	20	13	11	10	10	61
Debt Collection Agreement (7)	**122**	3	3	3	3	3	107
Operating lease obligations	**53**	11	9	7	4	4	18
Purchase of Springerville Common Facilities (8)	**85**	–	–	–	85	–	–
Waneta Partnership promissory note *(Note 16)*	**72**	–	–	72	–	–	–
Joint-use asset and shared service agreements	**52**	3	3	3	3	3	37
Other (9)	**462**	97	53	71	31	32	178
Total	**$ 21,622**	$ 1,842	$ 1,580	$ 1,570	$ 1,422	$ 1,227	$ 13,981

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

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

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

FortisBC Electric: Power purchase obligations for FortisBC Electric, totalling $333 million as at December 31, 2017, include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term. FortisBC Electric is also party to the Waneta Expansion Capacity Agreement ("WECA"), allowing it to purchase 234 MW of capacity per month, on average, for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Commitments table as they will be paid by FortisBC Electric to a related party.

Maritime Electric: Maritime Electric's power purchase obligations include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power"). Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, and as at December 31, 2017, had commitments of $511 million under this arrangement.

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

30. COMMITMENTS AND CONTINGENCIES (cont'd)

(3) Certain of the Corporation's subsidiaries, mainly FortisBC Energy, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2017.

(4) UNS Energy enters into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts.

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

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

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

(8) UNS Energy has an obligation to purchase an undivided 32.2% interest in the Springerville Common Facilities if the related two leases are not renewed (Note 15).

(9) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including PSU, RSU and DSU plan obligations, land easements, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Commitments

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $3.2 billion for 2018. Over the five-year period from 2018 through 2022, the Corporation's consolidated capital expenditure program is expected to be approximately $14.5 billion, which has not been included in the Commitments table.

Other: CH Energy Group is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling $2.1 billion (US$1.7 billion). CH Energy Group's maximum commitment is $228 million (US$182 million), for which it has issued a parental guarantee. As at December 31, 2017, there was no obligation under this guarantee.

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

The Corporation's regulatory liabilities of $3,446 million as at December 31, 2017 have been excluded from the Commitments table, as the final timing of settlement of such liabilities is subject to further regulatory determination or the settlement periods are not currently known (Note 8).

Contingencies

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

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court entered a decision dismissing the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the minister's consent and returned the matter to the minister for redetermination. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

31. COMPARATIVE FIGURES

The Corporation revised a line item within the financing activities section of its Statement of Cash Flow for the year ended December 31, 2016 to correct an immaterial error in the presentation of credit facility borrowings. 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. The correction resulted in $169 million, which was previously reported within Net Repayments and Borrowings under Committed Credit Facilities, being reported on a gross basis, with $668 million reported as Borrowings under Committed Credit Facilities and $499 million being reported as Repayments under Committed Credit Facilities. The correction did not change the total cash from financing activities.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2017** [1]	2016 [1][2]	2015 [1][2]
Revenue	**8,301**	6,838	6,757
Energy supply costs and operating expenses	**4,622**	4,372	4,465
Depreciation and amortization	**1,179**	983	873
Other income, net	**127**	53	197
Finance charges	**914**	678	553
Income tax expense	**588**	145	223
Earnings from continuing operations	**1,125**	713	840
Earnings from discontinued operations, net of tax	**–**	–	–
Extraordinary gain, net of tax	**–**	–	–
Net earnings	**1,125**	713	840
Net earnings attributable to non-controlling interests	**97**	53	35
Net earnings attributable to preference equity shareholders	**65**	75	77
Net earnings attributable to common equity shareholders	**963**	585	728
Balance Sheets *(in $ millions)*			
Current assets	**2,207**	2,166	1,857
Goodwill	**11,644**	12,364	4,173
Other long-term assets	**3,222**	3,026	2,638
Property, plant and equipment, non-utility capital assets[3] and intangible assets	**30,749**	30,348	20,136
Total assets	**47,822**	47,904	28,804
Current liabilities	**3,504**	3,944	2,638
Other long-term liabilities	**6,878**	6,693	5,029
Long-term debt (excluding current portion)	**20,691**	20,817	10,784
Preference shares (classified as debt)	**–**	–	–
Total liabilities	**31,073**	31,454	18,451
Shareholders' equity	**16,749**	16,450	10,353
Cash Flows *(in $ millions)*			
Operating activities	**2,756**	1,884	1,673
Investing activities	**(3,025)**	(6,891)	(1,368)
Financing activities, excluding dividends	**932**	5,491	(14)
Dividends, excluding dividends on preference shares classified as debt	**(593)**	(441)	(332)
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**7.31**	5.56	9.75
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease and finance obligations (net of cash)	**59.2**	60.6	54.8
Preference shares (classified as debt and equity)	**4.4**	4.4	8.3
Common shareholders' equity	**36.4**	35.0	36.9
Interest Coverage *(x)*			
Debt	**2.7**	2.1	2.7
All fixed charges	**2.7**	2.1	2.7
Total gross capital expenditures *(in $ millions)*	**3,024**	2,061	2,243
Common share data			
Book value per share (year end) *($)*	**31.77**	32.31	28.62
Average common shares outstanding *(in millions)*	**415.5**	308.9	278.6
Basic earnings per common share *($)*	**2.32**	1.89	2.61
Dividends declared per common share *($)*	**1.65**	1.55	1.43
Dividends paid per common share *($)*	**1.625**	1.525	1.40
Dividend payout ratio *(%)*	**70.0**	80.7	53.6
Price earnings ratio *(x)*	**19.9**	21.9	14.3
Share trading summary (TSX)			
High price *($)*	**48.73**	44.87	42.23
Low price *($)*	**40.59**	35.53	34.16
Closing price *($)*	**46.11**	41.46	37.41
Volume *(in thousands)*	**205,261**	293,991	172,038

(1) Financial information for the years 2010 through 2017 prepared under U.S. generally accepted accounting principles ("GAAP"); prior to 2010 prepared under Canadian GAAP.

(2) Results were impacted by non-operating items, largely associated with the acquisition of ITC in 2016, the sale of non-core assets in 2015, the acquisition of UNS Energy in 2014, and the acquisition of Central Hudson in 2013.

(3) Non-utility capital assets were sold as part of the sale of commercial real estate and hotel assets in 2015.

Historical Financial Summary

2014 (1)(2)	2013 (1)(2)	2012 (1)	2011 (1)	2010 (1)	2009	2008
5,401	4,047	3,654	3,738	3,647	3,641	3,907
3,690	2,654	2,390	2,547	2,448	2,577	2,859
688	541	470	416	406	364	348
(25)	(31)	4	38	13	10	–
547	389	366	363	359	369	363
66	32	61	84	72	49	65
385	400	371	366	375	292	272
5	–	–	–	–	–	–
–	20	–	–	–	–	–
390	420	371	366	375	292	272
11	10	9	9	10	12	13
62	57	47	46	45	18	14
317	353	315	311	320	262	245
1,787	1,296	1,093	1,132	1,205	1,124	1,150
3,732	2,075	1,568	1,565	1,561	1,560	1,575
2,410	1,925	1,715	1,580	1,309	917	487
18,304	12,612	10,574	9,937	9,336	8,538	7,954
26,233	17,908	14,950	14,214	13,411	12,139	11,166
2,676	2,084	1,350	1,305	1,491	1,592	1,697
4,534	3,024	2,449	2,281	1,977	1,325	763
9,911	6,424	5,741	5,685	5,616	5,239	4,848
–	–	–	–	–	320	320
17,121	11,532	9,540	9,271	9,084	8,476	7,628
9,112	6,376	5,410	4,943	4,327	3,663	3,538
982	899	992	915	742	681	661
(4,199)	(2,164)	(1,096)	(1,115)	(980)	(1,045)	(852)
3,627	1,434	396	386	451	563	387
(266)	(248)	(225)	(206)	(189)	(176)	(191)
5.45	8.06	8.06	8.79	10.06	8.41	8.70
56.4	56.2	55.3	57.1	60.4	60.2	59.5
9.1	9.0	9.7	8.3	8.7	6.9	7.3
34.5	34.8	35.0	34.6	30.9	32.9	33.2
1.6	1.9	2.0	2.0	2.0	1.9	1.9
1.6	1.9	2.0	2.0	2.0	1.8	1.8
1,725	1,175	1,146	1,171	1,071	1,024	935
24.89	22.38	20.84	20.25	18.65	18.61	17.97
225.6	202.5	190.0	181.6	172.9	170.2	157.4
1.41	1.74	1.66	1.71	1.85	1.54	1.56
1.30	1.25	1.21	1.17	1.41	0.78	1.01
1.28	1.24	1.20	1.16	1.12	1.04	1.00
90.8	71.3	72.3	67.8	60.5	67.5	64.1
27.6	17.5	20.6	19.5	18.4	18.6	15.8
40.83	35.14	34.98	35.45	34.54	29.24	29.94
29.78	29.51	31.70	28.24	21.60	21.52	20.70
38.96	30.45	34.22	33.37	33.98	28.68	24.59
174,566	120,470	115,962	126,341	120,855	121,162	132,108

Investor Information

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 18, 2018	August 21, 2018
November 20, 2018	February 15, 2019

Dividend Payment Dates

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

Earnings Release Dates

May 1, 2018	July 31, 2018
November 2, 2018	February 14, 2019

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

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare" or "Transfer Agent") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices in Canada and at the co-transfer agent's Canton, MA, Jersey City, NJ, and College Station, TX offices in the United States. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

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

Computershare Trust Company N.A.

Attn: Stock Transfer Department
Overnight Mail Delivery: 250 Royall Street, Canton, MA 02021
Regular Mail Delivery: P.O. Box 43078, Providence, RI 02940-3070

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian and U.S. financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

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

Annual Meeting

Thursday, May 3, 2018 – 10:30 a.m.
Holiday Inn St. John's, 180 Portugal Cove Road, St. John's, NL, Canada

Dividend Reinvestment Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP") as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (minimum of $100, maximum of $30,000 annually) automatically deposited in the plan to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

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 Inc. are listed on the Toronto Stock Exchange and trade 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.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

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President and Chief Executive Officer

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