FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2016

February 15, 2017

ANNUAL INFORMATION FORM

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

CONTENTS

FORWARD-LOOKING INFORMATION

The following 2016 Annual Information Form has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. Financial information for 2016 and comparative periods contained in the 2016 Annual Information Form has been prepared in accordance with US GAAP and is presented in Canadian dollars unless otherwise specified. Capitalized terms used herein are defined under the heading "Definitions" on page 3.

Except as otherwise stated, the information in the 2016 Annual Information Form is given as of December 31, 2016.

Fortis includes forward-looking information in this AIF within the meaning of applicable securities laws including the Private Securities Litigation Reform Act of 1995. Forward-looking statements included in this AIF reflect expectations of Fortis management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking statements, which include, without limitation: the expectation that the Corporation's 2017 results will benefit from ITC, the TEP general rate case and growth of the underlying business; the Corporation's forecast gross consolidated capital expenditures for the five-year period 2017 to 2021; the Corporation's forecast midyear rate base through 2021; the expectation that the Corporation's capital expenditure program will support continuing growth in earnings and dividends; target average annual dividend growth through 2021; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the expectation that allocated revenues recognized by ITC from Canadian entities reserving transmission over the Ontario or Manitoba interface are not expected to be material; the expectation that TEP has sufficient generating capacity to satisfy the requirements of its customer base and meet future peak demand requirements; the expectation that changes in energy supply costs may increase electricity prices in a manner that adversely affects Newfoundland Power's sales; the expectation that the Corporation's utilities will continue to seek recovery of prudently incurred compliance costs; and TEP's expected share of mine reclamation costs.

Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking statements, including, without limitation: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the 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 counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel, coal and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans, environmental laws and regulations that may materially negatively affect the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the continued tax deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure and no material breach of cyber security; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital program.

Forward-looking statements involve significant risks, uncertainties and assumptions. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking statements. These factors should be considered carefully and undue reliance should not be placed on the forward-looking statements. For additional information with respect to certain of these risks or factors, reference should be made to the MD&A for the year ended December 31, 2016 under the heading "Business Risk Management" and to the continuous disclosure materials filed from time to time by Fortis with Canadian securities regulatory authorities and the Securities and Exchange Commission. Key risk factors for 2017 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; uncertainty of the impact a continuation of a low interest rate environment may have on the allowed rate of return on common shareholders' equity at the Corporation's regulated utilities; the impact of fluctuations in foreign exchange rates; risk associated with the impacts of less favourable economic conditions on the Corporation's results of operations; risk that the expected benefits of the acquisition of ITC may fail to materialize, or may not occur within the time periods anticipated; risk associated with the Corporation's ability to comply with Section 404(a) of the Sarbanes-Oxley Act of 2002 and the related rules of the U.S. Securities and Exchange Commission and the Public Company Accounting Oversight Board; risk associated with the completion of the Corporation's 2017 capital expenditures plan, including completion of major capital projects in the timelines anticipated and at the expected amounts; and uncertainty in the timing and access to capital markets to arrange sufficient and cost-effective financing to finance, among other things, capital expenditures and the repayment of maturing debt.

All forward-looking information in this AIF is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

DEFINITIONS

Certain terms used in this 2016 Annual Information Form are defined below:

"2016 Annual Information Form" or **"AIF"** means this annual information form of the Corporation in respect of the year ended December 31, 2016;

"$"** or **"C$" means Canadian dollars;

"2016 Audited Consolidated Financial Statements" means the audited consolidated financial statements of the Corporation as at and for the years ended December 31, 2016 and 2015 and related notes thereto;

"ACGS" means Aitken Creek Gas Storage ULC;

"Aitken Creek" means the Aitken Creek gas storage site;

"Algoma Power" means Algoma Power Inc.;

"APS" means Arizona Public Service Company;

"AUC" means the Alberta Utilities Commission;

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

"BCUC" means the British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

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

"BPC" means Brilliant Power Corporation;

"Business Acquisition Report" means the business acquisition report of Fortis relating to its October 14, 2016 acquisition of ITC;

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

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

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

"CEPSA" means the Capacity and Energy Purchase and Sale Agreement;

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

"Common Shares" means the common shares of the Corporation;

"COPE" means the Canadian Office and Professional Employees Union;

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

"Corporation" means Fortis Inc.;

"CPA" means the Canal Plant Agreement;

"CPC/CBT" means Columbia Power Corporation and Columbia Basin Trust;

"CUPE" means the Canadian Union of Public Employees;

"DBRS" means DBRS Limited;

"Eastern Canadian Electric Utilities" means, collectively, the operations of Newfoundland Power, Maritime Electric and FortisOntario;

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

"Endangered Species Act" means the United States Endangered Species Act;

"Ethos" means EthosEnergy Power Plant Services, LLC;

"External Auditor" means the firm of Chartered Professional Accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"FAES" means FortisBC Alternative Energy Services Inc.;

"FERC" means the United States Federal Energy Regulatory Commission;

"FHI" means FortisBC Holdings Inc., the parent company of FortisBC Energy;

"Fitch" means Fitch Ratings Inc.;

"Fortis" means Fortis Inc.;

"FortisAlberta" means FortisAlberta Inc.;

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

"FortisBC Energy" means FortisBC Energy Inc.;

"FortisOntario" means FortisOntario Inc.;

"Fortis Properties" means Fortis Properties Corporation;

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

"FortisUS" means FortisUS Inc.;

"FortisUS Holdings" means FortisUS Holdings Nova Scotia Limited;

"FortisWest" means FortisWest Inc.;

"**Four Corners"** means the Four Corners Generating Station;

"GHG" means greenhouse gas;

"GIC" means GIC Private Limited;

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

"IBEW" means the International Brotherhood of Electrical Workers;

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

"IPL" means Interstate Power and Light Company;

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

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

"ITC Holdings" means ITC Holdings Corp.;

"ITC Interconnection" means ITC Interconnection LLC;

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

"ITC Midwest" means ITC Midwest LLC;

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

"ITCTransmission" means International Transmission Company;

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

"LNG" means liquefied natural gas;

"Management" means, collectively, the senior officers of the Corporation;

"Maritime Electric" means Maritime Electric Company, Limited;

"MD&A" means the Corporation's Management Discussion and Analysis prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations,* in respect of the Corporation's annual consolidated financial statements for the year ended December 31, 2016;

"METC" means Michigan Electric Transmission Company;

"MGP" means manufactured gas plant;

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

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

"NB Power" means New Brunswick Power Corporation;

"NEB" means the National Energy Board;

"NEPA" means the United States National Environmental Policy Act;

"Newfoundland Hydro" means Newfoundland and Labrador Hydro Corporation;

"Newfoundland Power" means Newfoundland Power Inc.;

"NYISO" means the New York Independent System Operator;

"NYSE" means the New York Stock Exchange;

"OEB" means the Ontario Energy Board;

"OSM" means the United States Office of Surface Mining;

"PEI" means Prince Edward Island;

"PNM" means Public Service Company of New Mexico;

"PPA" means power purchase agreement;

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

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

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

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

"SJCC" means the San Juan Coal Company;

"Spectra Energy" means Westcoast Energy Inc. doing business as Spectra Energy Transmission;

"SPP" means Southwest Power Pool, Inc.;

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

"T&D" means transmission and distribution;

"TEP" means Tucson Electric Power Company;

"TransCanada" means TransCanada Pipelines Limited;

"TSX" means the Toronto Stock Exchange;

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

"UNS Energy" means collectively, the operations of TEP, UNS Electric and UNS Gas;

"UNS Gas" means UNS Gas, Inc.;

"US$" means U.S. dollars;

"USA" means the United States of America;

"US GAAP" means accounting principles generally accepted in the United States;

"US Securities Act" means the *United States Securities Act*, as amended;

"UUWA" means the United Utility Workers' Association of Canada;

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

"Waneta Partnership" means the Waneta Expansion Limited Partnership;

"WEG" means WildEarth Guardians.

Conversions

1 litre = 0.22 imperial gallons
1 kilometre = 0.62 miles

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

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

Measurements

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

CORPORATE STRUCTURE

Name and Incorporation

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

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

Inter-Corporate Relationships

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at February 15, 2017. This table excludes certain subsidiaries. The assets and revenues of excluded subsidiaries did not individually exceed 10%, or in the aggregate exceed 20% of the total consolidated assets or total consolidated revenues of the Corporation as at December 31, 2016. The principal subsidiaries together comprise approximately 88% of the Corporation's consolidated assets as at December 31, 2016 and approximately 82% of the Corporation's 2016 consolidated revenue.

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

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

(2) *UNS Energy, an Arizona corporation, owns all of the shares of TEP, UNS Electric and UNS Gas. FortisUS, a Delaware corporation, owns all of the shares of UNS Energy. FortisUS Holdings, a Canadian corporation, owns all of the shares of FortisUS. Fortis owns all of the shares of FortisUS Holdings.*

(3) *CH Energy Group, a New York State corporation, owns all of the shares of Central Hudson. FortisUS, a Delaware corporation, owns all of the shares of CH Energy Group. FortisUS Holdings, a Canadian corporation, owns all of the shares of FortisUS. Fortis owns all of the shares of FortisUS Holdings.*

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

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

(6) *The Corporation owns all of the common shares and certain of the First Preference Shares, Series A, B, D and G of Newfoundland Power, which, as at February 15, 2017, represent 95% of its voting securities. The remaining 5% of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G, which are primarily held by the public.*

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Fortis is a leader in the North American regulated electric and gas utility business, with total assets of approximately $48 billion and fiscal 2016 revenue of $6.8 billion. More than 8,000 employees of the Corporation serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. In 2016 the Corporation's electricity systems met a combined peak demand of 33,021 MW and its gas distribution systems met a peak day demand of 1,586 TJ. As at December 31, 2016, approximately 66% of the Corporation's assets were located outside of Canada and approximately 51% of the Corporation's revenue was derived from foreign operations.

Three-Year History

Over the past three years, Fortis has experienced significant growth in its business operations. Total assets have more than doubled from $17.9 billion as at December 31, 2013 to $48.0 billion as at December 31, 2016. The Corporation's shareholders' equity has also grown significantly from $6.4 billion as at December 31, 2013 to $16.5 billion as at December 31, 2016. Net earnings attributable to common equity shareholders have increased from $353 million in 2013 to $585 million in 2016.

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

In August 2014, Fortis acquired UNS Energy, a vertically integrated utility services holding company, for a purchase price of approximately US$4.5 billion, including the assumption of approximately US$2.0 billion of debt on closing.

In April 2015, the Corporation completed construction of the $900 million, 335-MW Waneta Expansion hydroelectric generating facility ahead of schedule and on budget. Fortis has a 51% controlling ownership interest in the Waneta Expansion and operates and maintains the non-regulated investment.

In June 2015, the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million to a subsidiary of Slate Office REIT. As part of the transaction, Fortis subscribed to trust units of Slate Office REIT for total consideration of approximately $35 million. In November 2016, Fortis sold its Slate Office REIT trust units for aggregate gross proceeds of approximately $37 million.

In October 2015, the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million to a private investor group.

In June and July of 2015, the Corporation completed the sale of its non-regulated generation assets in Upstate New York and Ontario, respectively, for gross proceeds of approximately $93 million.

In August 2015, the Corporation reached a settlement with the Government of Belize regarding the expropriation of the Corporation's approximate 70% interest in Belize Electricity. The terms of the settlement included a one-time US$35 million cash payment to Fortis and an approximate 33% equity investment in Belize Electricity.

In April 2016, the Corporation completed the acquisition of ACGS for approximately $349 million (US$266 million), plus the cost of working gas inventory. ACGS owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company. Aitken Creek is the only underground gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet. The facility is an integral part of western Canada's natural gas transmission network.

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

In connection with the acquisition of ITC, in May 2016 Fortis became a SEC registrant and in October 2016 its Common Shares commenced trading on the NYSE. The Corporation filed a Business Acquisition Report in connection with its acquisition of ITC on SEDAR and EDGAR on November 23, 2016.

The Corporation's gross consolidated capital expenditures for 2016 were approximately $2.1 billion. Over the past three years, including 2016, gross consolidated capital expenditures totalled $6.0 billion. Organic asset growth has been driven by the capital expenditure programs at the Corporation's regulated utilities. Organic growth in non-regulated operations has been driven by the construction of the Waneta Expansion.

Outlook

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

Over the five-year period through 2021, the Corporation's capital program is expected to be approximately $13 billion, allowing rate base to reach almost $30 billion in 2021. Fortis expects this long-term sustainable growth in rate base to support continuing growth in earnings and dividends.

Fortis has targeted average annual dividend growth of approximately 6% through 2021. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure program, and Management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

DESCRIPTION OF THE BUSINESS

Fortis is principally a regulated electric and gas utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated energy infrastructure, which is treated as a separate segment. The Corporation's reporting segments allow Management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The majority of the Corporation's regulated utilities operate as the sole supplier of electricity and/or gas within their respective service territories. The Corporation's regulated utilities own and operate facilities that generate, transmit and distribute electricity and/or gas to their customers. Competition in the regulated electric business is primarily from on-site generation of industrial customers and distributed generation, such as rooftop solar, at residential, general service and/or industrial customer sites. The Corporation faces competition in its transmission business which may restrict its ability to grow such business outside of its established service territories.

At the Corporation's regulated gas utilities, natural gas primarily competes with electricity for space and hot water heating load. The growth in the North American natural gas supply, primarily from shale gas production, has resulted in a lower natural gas price environment, which has helped improve natural gas competitiveness on an operating basis. Nevertheless, upfront capital cost differences between electricity and natural gas equipment continue to present a challenge for the competitiveness of natural gas on a fully-costed basis.

As the Corporation's subsidiaries operate in various jurisdictions throughout North America, seasonality impacts each utility differently. Most of the annual earnings of the Corporation's gas utilities are realized in the first and fourth quarters due to space-heating requirements in colder weather. Earnings for the electric utilities in the United States are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment in the summer.

The following sections describe the operations included in each of the Corporation's reportable segments.

ITC

ITC's business consists primarily of the electric transmission operations of the ITC Regulated Operating Subsidiaries. In 2002, ITC Holdings was incorporated in the State of Michigan for the purpose of acquiring ITCTransmission. ITCTransmission was originally formed in 2001 as a subsidiary of DTE Electric Company, an electric utility subsidiary of DTE Energy Company, and was acquired in 2003 by ITC Holdings. METC was originally formed in 2001 as a subsidiary of Consumers Energy Company, an electric and gas utility subsidiary of CMS Energy Corporation, and was acquired in 2006 by ITC Holdings. ITC Midwest was formed in 2007 by ITC Holdings and acquired the transmission assets of IPL in December 2007. ITC Great Plains was formed in 2006 by ITC Holdings and became a FERC-jurisdictional entity in 2009. ITC Interconnection was formed in 2014 by ITC Holdings and became a FERC-jurisdictional entity in June 2016 after acquiring certain transmission assets from a merchant generating company and placing a newly constructed transmission line in service. ITC owns and operates high-voltage systems in Michigan's Lower Peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from generating stations to local distribution facilities connected to ITC's systems. ITC owns and operates approximately 25,000 kilometres of transmission lines.

ITC's business strategy is to own, operate, maintain and invest in transmission infrastructure in order to enhance system integrity and reliability, reduce transmission constraints and support new generating resources to interconnect to ITC's transmission systems. ITC is also pursuing development projects not connected to its existing systems, which are intended to improve overall grid reliability, reduce transmission constraints and facilitate interconnections of new generating resources, as well as enhance competitive wholesale electricity markets.

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

ITC's principal transmission service customers are DTE Electric Company, Consumers Energy Company and IPL, which accounted for approximately 20.7%, 21.7% and 25.5%, respectively, of its consolidated billed revenues for the year ended December 31, 2016. The percentages of total billed revenues from DTE Electric Company, Consumers Energy Company and IPL include the collection of 2014 revenue accruals and deferrals and exclude any amounts for the 2016 revenue accruals and deferrals that were included in ITC's 2016 operating revenues, but will not be billed to ITC's customers until 2018. One or more of these customers together have consistently represented a significant percentage of ITC's operating revenue. Nearly all of ITC's revenues are from transmission customers in the United States. Although ITC may recognize allocated revenues from time to time from Canadian entities reserving transmission over the Ontario or Manitoba interface, these revenues have not been and are not expected to be material to ITC.

ITC's Regulated Operating Subsidiaries calculate their revenue requirements using cost-based formula rates and are effective without having to file rate cases with the FERC, although the rates are subject to legal challenge at FERC. Under their cost-based formula rates, each of ITC's Regulated Operating Subsidiaries separately calculates a revenue requirement based on financial information specific to each company. The calculation of projected revenue requirement for a future period is used to establish the transmission rate used for billing purposes. The calculation of actual revenue requirements for a historic period is used to calculate the amount of revenues recognized in that period and determine the over- or under-collection for that period.

Under these formula rates, ITC's Regulated Operating Subsidiaries recover expenses and earn a return on and recover investments in property, plant and equipment on a current basis, rather than lagging. The formula rate for a given year initially utilizes forecasted expenses, property, plant and equipment, point-to-point revenues, network load at ITC's MISO Regulated Operating Subsidiaries and other items for the upcoming calendar year to establish projected revenue requirements for each of ITC's Regulated Operating Subsidiaries that are used as the basis for billing for service on their systems from January 1 to December 31 of that year. ITC's rates include a true-up mechanism, whereby ITC's Regulated Operating Subsidiaries compare their actual revenue requirements to their billed revenues for each year to determine any over- or under-collection of revenue. The over- or under-collection typically results from differences between the projected revenue requirement used as the basis for billing and actual revenue requirement at each of ITC's Regulated Operating Subsidiaries, or from differences between actual and projected monthly peak loads at ITC's MISO Regulated Operating Subsidiaries. In the event billed revenues in a given year are more or less than actual revenue requirements, which are calculated primarily using information from that year's FERC Form No. 1, ITC's Regulated Operating Subsidiaries will refund or collect additional revenues, with interest, within a two-year period such that customers pay only the amounts that correspond to actual revenue requirements for that given period. This annual true-up ensures that ITC's Regulated Operating Subsidiaries recover their allowed costs and earn their allowed returns.

Market and Sales

Revenues

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

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

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

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

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

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

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

The following table compares the composition of ITC's 2016 and 2015 revenue by customer class.

	Revenue (%) (1)	
	2016	2015
Network revenues	**72**	77
Regional cost sharing revenues	**30**	31
Point-to-point	**2**	2
Scheduling, control and dispatch	**1**	1
Other	**2**	1
Recognition of refund liabilities (2)	**(7)**	(12)
Total	**100**	100

(1) *The information presented is for the year ended December 31, 2016. ITC was acquired by Fortis in October 2016; therefore, only financial results from the date of acquisition, October 14, 2016, are reflected in the Corporation's 2016 Audited Consolidated Financial Statements.*

(2) *Mainly represents return on common shareholder's equity refund liabilities associated with third-party complaints filed with FERC challenging the base return on common shareholder's equity of the ITC MISO Regulated Operating Subsidiaries.*

Contracts

ITCTransmission

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

Master Operating Agreement. The Master Operating Agreement (the "MOA"), dated as of February 28, 2003, governs the primary day-to-day operational responsibilities of ITCTransmission and DTE Electric Company and will remain in effect until terminated by mutual agreement of the parties (subject to any required FERC approvals) unless earlier terminated pursuant to its terms. The MOA identifies the control area coordination services that ITCTransmission is obligated to provide to DTE Electric. The MOA also requires DTE Electric to provide certain generation-based support services to ITCTransmission.

Generator Interconnection and Operation Agreement. DTE Electric Company and ITCTransmission entered into the Generator Interconnection and Operation Agreement (the "GIOA"), dated as of February 28, 2003, in order to establish, re-establish and maintain the direct electricity interconnection of DTE Electric Company's electricity generating assets with ITCTransmission's transmission system for the purposes of transmitting electric power from and to the electricity generating facilities. Unless otherwise terminated by mutual agreement of the parties (subject to any required FERC approvals), the GIOA will remain in effect until DTE Electric Company elects to terminate the agreement with respect to a particular unit or until a particular unit ceases commercial operation.

Coordination and Interconnection Agreement. The Coordination and Interconnection Agreement (the "CIA"), dated as of February 28, 2003, governs the rights, obligations and responsibilities of ITCTransmission and DTE Electric Company regarding, among other things, the operation and interconnection of DTE Electric Company's distribution system and ITCTransmission's transmission system, and the construction of new facilities or modification of existing facilities. Additionally, the CIA allocates costs for operation of supervisory, communications and metering equipment. The CIA will remain in effect until terminated by mutual agreement of the parties (subject to any required FERC approvals).

METC

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

Amended and Restated Easement Agreement. Under the Amended and Restated Easement Agreement (the "Easement Agreement"), dated as of April 29, 2002 and as further supplemented, Consumers Energy Company provides METC with an easement to the land, referred to as premises, on which a majority of METC's transmission towers, poles, lines and other transmission facilities used to transmit electricity at voltages of at least 120 kV are located, referred to collectively as the facilities. Consumers Energy Company retained for itself the rights to, and the value of activities associated with, all other uses of the premises and the facilities covered by the Easement Agreement, such as for distribution of electricity, fiber optics, telecommunications, gas pipelines and agricultural uses. Accordingly, METC is not permitted to use the premises or the facilities covered by the Easement Agreement for any purposes other than to provide electric transmission and related services, to inspect, maintain, repair, replace and remove electric transmission facilities and to alter, improve, relocate and construct additional electric transmission facilities. The easement is further subject to the rights of any third parties that had rights to use or occupy the premises or the facilities prior to April 1, 2001 in a manner not inconsistent with METC's permitted uses.

METC pays Consumers Energy Company annual rent of US$10 million, in equal quarterly installments, for the easement and related rights under the Easement Agreement. Although METC and Consumers Energy Company share the use of the premises and the facilities covered by the Easement Agreement, METC pays the entire amount of any rentals, property taxes, inspection fees and other amounts required to be paid to third parties with respect to any use, occupancy, operations or other activities on the premises or the facilities and is generally responsible for the maintenance of the premises and the facilities used for electric transmission at its expense. METC must also maintain commercial general liability insurance protecting METC and Consumers Energy Company against claims for personal injury, death or property damage occurring on the premises or the facilities and pay for all insurance premiums. METC is also responsible for patrolling the premises and the facilities by air at its expense at least annually and for notifying Consumers Energy Company of any unauthorized uses or encroachments discovered. METC must indemnify Consumers Energy Company for all liabilities arising from the facilities covered by the Easement Agreement.

METC must notify Consumers Energy Company before altering, improving, relocating or constructing additional transmission facilities covered by the Easement Agreement. Consumers Energy Company may respond by notifying METC of reasonable work and design restrictions and precautions that are needed to avoid endangering existing distribution facilities, pipelines or communications lines, in which case METC must comply with these restrictions and precautions. METC has the right at its own expense to require Consumers Energy Company to remove and relocate these facilities, but Consumers Energy Company may require payment in advance or the provision of reasonable security for payment by METC prior to removing or relocating these facilities, and Consumers Energy Company need not commence any relocation work until an alternative right-of-way satisfactory to Consumers Energy Company is obtained at METC's expense.

The term of the Easement Agreement runs through December 31, 2050 and is subject to 10 automatic 50-year renewals after that time unless METC provides one year's notice of its election not to renew the term. Consumers Energy Company may terminate the Easement Agreement 30 days after giving notice of a failure by METC to pay its quarterly installment if METC does not cure the non-payment within the 30-day notice period. At the end of the term or upon any earlier termination of the Easement Agreement, the easement and related rights terminate and the transmission facilities revert to Consumers Energy Company.

Amended and Restated Operating Agreement. Under the Amended and Restated Operating Agreement (the "Operating Agreement"), dated as of April 29, 2002, METC agrees to operate its transmission system to provide all transmission customers with safe, efficient, reliable and nondiscriminatory transmission service pursuant to its tariff. Among other things, METC is responsible under the Operating Agreement for maintaining and operating its transmission system, providing Consumers Energy Company with information and access to its transmission system and related books and records, administering and performing the duties of control area operator (that is, the entity exercising operational control over the transmission system) and, if requested by Consumers Energy Company, building connection facilities necessary to permit interaction with new distribution facilities built by Consumers Energy Company. Consumers Energy Company has corresponding obligations to provide METC with access to its books and records and to build distribution facilities necessary to provide adequate and reliable transmission services to wholesale customers. Consumers Energy Company must cooperate with METC as METC performs its duties as control area operator, including by providing reactive supply and voltage control from generation sources or other ancillary services and reducing load. The Operating Agreement is effective through 2050 and is subject to 10 automatic 50-year renewals after that time, unless METC provides one year's notice of its election not to renew.

Amended and Restated Purchase and Sale Agreement for Ancillary Services. The Amended and Restated Purchase and Sale Agreement for Ancillary Services (the "Ancillary Services Agreement") is dated as of April 29, 2002. Since METC does not own any generating facilities, it must procure ancillary services from third party suppliers, such as Consumers Energy Company. Currently, under the Ancillary Services Agreement, METC pays Consumers Energy Company for providing certain generation based services necessary to support the reliable operation of the bulk power grid, such as voltage support and generation capability and capacity to balance loads and generation. METC is not precluded from procuring these ancillary services from third party suppliers when available. The Ancillary Services Agreement is subject to rolling one-year renewals starting May 1, 2003, unless terminated by either METC or Consumers Energy Company with six months prior written notice.

Amended and Restated Distribution-Transmission Interconnection Agreement. The Amended and Restated Distribution-Transmission Interconnection Agreement (the "DT Interconnection Agreement"), dated April 1, 2001 and most recently amended and restated effective as of January 1, 2015, provides for the interconnection of Consumers Energy Company's distribution system with METC's transmission system and defines the continuing rights, responsibilities and obligations of the parties with respect to the use of certain of their own and the other party's properties, assets and facilities. METC agrees to provide Consumers Energy Company interconnection service at agreed-upon interconnection points, and the parties have mutual responsibility for maintaining voltage and compensating for reactive power losses resulting from their respective services. The DT Interconnection Agreement is effective so long as any interconnection point is connected to METC's facilities, unless it is terminated earlier by mutual agreement of METC and Consumers Energy Company.

Amended and Restated Generator Interconnection Agreement. The Amended and Restated Generator Interconnection Agreement (the "Generator Interconnection Agreement"), dated as of April 29, 2002 and most recently amended effective as of October 1, 2016, specifies the terms and conditions under which Consumers Energy Company and METC maintain the interconnection of Consumers Energy Company's generation resources and METC's transmission assets. The Generator Interconnection Agreement is effective either until it is replaced by any MISO-required contract, or until METC and Consumers Energy Company mutually agree to terminate, but not later than the date that all listed generators cease commercial operation.

ITC Midwest

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

Distribution-Transmission Interconnection Agreement. The Distribution-Transmission Interconnection Agreement (the "DTIA"), dated as of December 17, 2007 and amended and restated effective as of December 1, 2016, governs the rights, responsibilities and obligations of ITC Midwest and IPL, with respect to the use of certain of their own and the other parties' property, assets and facilities and the construction of new facilities or modification of existing facilities. Additionally, the DTIA sets forth the terms pursuant to which the equipment and facilities and the interconnection equipment of IPL will continue to connect ITC Midwest's facilities through which ITC Midwest provides transmission service under the MISO Open Access Transmission Energy and Operating Reserve Markets Tariff. The DTIA will remain in effect until terminated by mutual agreement by the parties (subject to any required FERC approvals) or as long as any interconnection point of IPL is connected to ITC Midwest's facilities, unless modified by written agreement of the parties.

Large Generator Interconnection Agreement. ITC Midwest, IPL and MISO entered into the Large Generator Interconnection Agreement (the "LGIA"), dated as of December 20, 2007 and amended as of August 6, 2013, in order to establish, re-establish and maintain the direct electricity interconnection of IPL's electricity generating assets with ITC Midwest's transmission system for the purposes of transmitting electric power from and to the electricity generating facilities. The LGIA will remain in effect until terminated by ITC Midwest or until IPL elects to terminate the agreement if a particular unit ceases commercial operation for three consecutive years.

UNS Energy

UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona. It is engaged through its subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 669,000 electricity and gas customers. UNS Energy is primarily comprised of three wholly owned regulated utilities: TEP, UNS Electric and UNS Gas.

TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP serves approximately 420,000 retail customers in a territory comprising approximately 2,991 square kilometres in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP's service area covers a population of approximately 1,200,000 people. TEP also sells wholesale electricity to other entities in the western United States.

UNS Electric is a vertically integrated regulated electric utility that generates, transmits and distributes electricity to approximately 95,000 retail customers in Arizona's Mohave and Santa Cruz counties, which have a combined population of approximately 251,000.

TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,994 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. TEP has sufficient generating capacity that, together with existing PPAs and expected generation plant additions, are expected to satisfy the requirements of its customer base and meet future peak demand requirements. As at December 31, 2016, approximately 47% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility that serves approximately 154,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties, which have a combined population of approximately 721,000.

Market and Sales

UNS Energy's electricity sales were 14,387 GWh for 2016, compared to 15,366 GWh for 2015. Earnings for UNS Energy's electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment. Gas volumes were 13 PJ for 2016 and 2015. Revenue was US$1,513 million for 2016, compared to US$1,588 million for 2015.

The following table provides the composition of UNS Energy's 2016 and 2015 revenue, electricity sales, and gas volumes by customer class.

	Revenue (%)		GWh Sales (%)		PJ Volumes (%)	
	2016	2015	**2016**	2015	**2016**	2015
Residential	**38.0**	37.3	**31.8**	29.8	**54.6**	55.1
Commercial	**23.4**	22.5	**19.3**	17.7	**23.8**	23.7
Industrial	**16.3**	17.0	**21.9**	21.8	**2.0**	2.0
Other [(1)]	**22.3**	23.2	**27.0**	30.7	**19.6**	19.2
Total	**100.0**	100.0	**100.0**	100.0	**100.0**	100.0

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

Power Supply

TEP meets the electricity supply requirements of its retail and wholesale customers with its owned electrical generating capacity of 2,696 MW and its transmission and distribution system consisting of approximately 15,700 kilometres of line. In 2016, TEP met a peak demand of 2,936 MW which includes firm sales to wholesale customers. TEP is a member of a regional reserve-sharing organization and has reliability and power sharing relationships with other utilities.

TEP's generating capacity as of December 31, 2016 is set forth in the following table.

Generating Source	Unit No.	Location	Date in Service	Resource Type	Total Capacity (MW)	Operating Agent	TEP's Share (%)	TEP's Share (MW)
Springerville Station [(1)]	1	Springerville, AZ	1985	Coal	387	TEP	100.0	387
Springerville Station [(2)]	2	Springerville, AZ	1990	Coal	406	TEP	100.0	406
San Juan Station	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
San Juan Station	2	Farmington, NM	1973	Coal	340	PNM	50.0	170
Navajo Station	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo Station	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo Station	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	Coal	785	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	785	APS	7.0	55
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	Ethos	75.0	413
Luna Generating Station	1	Deming, NM	2006	Gas	555	PNM	33.3	185
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	Tucson, AZ	1962	Gas	104	TEP	100.0	104
Sundt Station	4	Tucson, AZ	1967	Gas	156	TEP	100.0	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100.0	50
DeMoss Petrie		Tucson, AZ	2001	Gas	75	TEP	100.0	75
North Loop		Tucson, AZ	2001	Gas	94	TEP	100.0	94
Springerville Solar Station		Springerville, AZ	2002-2014	Solar	16	TEP	100.0	16
Tucson Solar Projects		Tucson, AZ	2010-2014	Solar	13	TEP	100.0	13
Ft. Huachuca Project [(3)]		Ft. Huachuca, AZ	2014	Solar	17	TEP	100.0	17
Total Capacity [(4)]								**2,696**

[(1)] *In September 2016, TEP purchased a 50.5% undivided interest in Springerville Unit 1 for US$85 million as part of a settlement agreement, increasing its total ownership to 100%.*

[(2)] *Springerville Unit 2 is owned by San Carlos Resources, Inc., a wholly-owned subsidiary of TEP.*

[(3)] *In January 2017, a second phase of the Ft. Huachuca Project was commissioned adding 5 MW of solar to TEP's total generating capacity.*

[(4)] *Excludes 781 MW of additional generation resources, which consist of certain capacity purchases and interruptible retail load.*

UNS Electric meets the electricity supply requirements of its retail customers through a mix of its own generation and power purchase contracts. UNS Electric owns and operates several gas and diesel-fuelled generating plants, with a collective electrical generating capacity of 298 MW, which provided approximately 66% of its 450 MW 2016 peak capacity needs.

UNS Electric's generating capacity as of December 31, 2016 is set forth in the following table.

Generating Source	Unit No.	Location	Date In Service	Resource Type	Total Capacity (MW)	Operating Agent	UNSE's Share (%)	UNSE's Share (MW)
Black Mountain	1	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Black Mountain	2	Kingman, AZ	2011	Gas	45	UNSE	100.0	45
Valencia	1	Nogales, AZ	Purchased 2003	Gas/Oil	14	UNSE	100.0	14
Valencia	2	Nogales, AZ	Purchased 2003	Gas/Oil	14	UNSE	100.0	14
Valencia	3	Nogales, AZ	Purchased 2003	Gas/Oil	14	UNSE	100.0	14
Valencia	4	Nogales, AZ	Purchased 2003	Gas/Oil	21	UNSE	100.0	21
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	Ethos	25.0	137
La Senita		Kingman, AZ	2011	Solar	1	UNSE	100.0	1
Rio Rico		Rio Rico, AZ	2014	Solar	7	UNSE	100.0	7
Total Capacity								**298**

Each of TEP and UNS Electric are subject to government-mandated renewable energy requirements. TEP satisfies these requirements through its 46 MW of owned photovoltaic solar generating capacity and PPAs for capacity from solar resources (196 MW), wind resources (80 MW) and a landfill gas generation plant (4 MW). UNS Electric satisfies its renewable energy requirements through its 8 MW of owned photovoltaic solar generating capacity and PPAs for capacity from solar resources (48 MW) and wind resources (10 MW).

Gas Purchases

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

UNS Gas purchases the majority of its gas supply from the San Juan Basin. The gas is delivered on the El Paso Natural Gas, L.L.C. and Transwestern Pipeline Company interstate pipeline systems under firm transportation agreements with combined capacity sufficient to meet the demands of UNS Gas' customers.

Central Hudson

Central Hudson is a regulated T&D utility serving approximately 300,000 electricity customers and 79,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley.

Central Hudson serves a territory comprising approximately 6,734 square kilometres in the Hudson Valley. Electric service is available throughout the territory, and natural gas service is provided in and about the cities of Poughkeepsie, Beacon, Newburgh, and Kingston, New York, and in certain outlying and intervening territories.

Central Hudson's electric transmission system consists of approximately 1,000 kilometres of line. The Central Hudson electric distribution system consists of approximately 11,600 kilometres of overhead lines and 2,400 trench kilometres of underground lines, as well as customer service lines and meters. Central Hudson's electricity system met a peak demand of 1,088 MW in 2016.

Central Hudson's natural gas system consists of approximately 300 kilometres of transmission pipelines and 2,000 kilometres of distribution pipelines, as well as customer service lines and meters. In 2016 Central Hudson's natural gas system met a peak day demand of 149 TJ.

Market and Sales

Central Hudson's electricity sales were 5,112 GWh for 2016, compared to 5,132 GWh for 2015. Natural gas sales volumes for 2016 were 24 PJ, compared to 24 PJ for 2015. Revenue was US$640 million for 2016, compared to US$691 million in 2015.

The following table compares the composition of Central Hudson's 2016 and 2015 revenue, electricity sales and gas volumes by customer class.

	Revenue (%)		GWh Sales (%)		PJ Volumes (%)	
	2016	2015	**2016**	2015	**2016**	2015
Residential	**61.3**	59.2	**41.4**	40.6	**24.6**	26.1
Commercial	**26.7**	26.4	**37.5**	38.0	**33.0**	33.1
Industrial	**4.4**	5.0	**19.5**	19.7	**21.8**	20.2
Other	**5.5**	6.9	**0.6**	0.7	**7.4**	7.7
Sales for Resale	**2.1**	2.5	**1.0**	1.0	**13.2**	12.9
Total	**100.0**	100.0	**100.0**	100.0	**100.0**	100.0

Power Supply

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

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

During 2016, Central Hudson entered into an agreement with Entergy Nuclear Power Marketing, LLC to purchase electricity, on a unit contingent basis at defined prices, from December 1, 2016 through March 31, 2017. The maximum commitment under this agreement is approximately US$3.3 million. Energy supplied under this agreement cost approximately US$0.5 million in 2016.

During 2015 Central Hudson entered into agreements to purchase electricity on a unit-contingent basis at defined prices during peak load periods from June 2015 through August 2016, replacing existing contracts which expired in March 2015. Energy supplied under these agreements cost approximately US$9.6 million in 2016.

Central Hudson is a party to PPAs to purchase capacity from the Danskammer Generating Facility, expiring August 2018, and the Roseton Generating Facility, expiring April 2017. Approximately US$48.2 million and US$2.7 million, respectively, in purchase commitments remain as at December 31, 2016.

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

Regulated Gas & Electric Utilities – Canadian

FortisBC Energy

FortisBC Energy is the largest distributor of natural gas in British Columbia, serving approximately 994,000 residential, commercial and industrial and transportation customers in more than 135 communities. Major areas served by FortisBC Energy include the Mainland, Vancouver Island and Whistler regions of British Columbia. FortisBC Energy provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers.

FortisBC Energy owns and operates approximately 49,000 kilometres of natural gas pipelines and met a peak day demand of 1,334 TJ in 2016.

Market and Sales

FortisBC Energy's natural gas sales volumes were 197 PJ in 2016, compared to 186 PJ in 2015. Revenue decreased from $1,295 million in 2015 to $1,151 million in 2016.

The following table compares the composition of FortisBC Energy's 2016 and 2015 revenue and natural gas volumes by customer class.

	Revenue (%)		PJ Volumes (%)	
	2016	2015	**2016**	2015
Residential	57.0	56.8	36.0	35.8
Commercial	27.5	29.1	21.8	23.0
Industrial	1.7	1.7	2.0	1.6
Transportation	9.3	7.8	34.5	33.7
Other (1)	4.5	4.6	5.7	5.9
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes amounts under fixed-revenue contracts, revenue from sources other than from the sale of natural gas and other regulatory adjustments, such as deferral mechanisms, that are recorded for rate setting purposes.*

Gas Purchase Agreements

In order to ensure supply of adequate resources to provide reliable natural gas deliveries to its customers, FortisBC Energy purchases natural gas supply from counterparties, including producers, aggregators and marketers. FortisBC Energy contracts for approximately 144 PJ of baseload and seasonal supply, of which the majority is sourced in north east British Columbia and transported on Spectra Energy's Westcoast Pipeline Transmission-South pipeline system. The remainder is sourced in Alberta and transported on TransCanada's pipeline transportation system.

FortisBC Energy procures and delivers natural gas directly to core market customers. Transportation only customers are responsible to procure and deliver their own natural gas to the FortisBC Energy system and FortisBC Energy then delivers the gas to the operating premises of these customers. FortisBC Energy contracts for transportation capacity on third party pipelines, such as Spectra and TransCanada, to transport gas supply from various market hubs to FortisBC Energy's system. These third-party pipelines are regulated by the NEB. FortisBC Energy pays both fixed and variable charges for the use of transportation capacity on these pipelines, which are recovered through rates paid by FortisBC Energy's core market customers. FortisBC Energy contracts for firm transportation capacity in order to ensure it is able to meet its obligation to supply customers within its broad operating region under all reasonable demand scenarios.

Gas Storage and Peak-Shaving Arrangements

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

FortisBC Energy holds approximately 35.2 PJs of total storage capacity. FortisBC Energy owns Tilbury and Mount Hayes LNG peak shaving facilities, which provide on-system storage capacity and deliverability. FortisBC Energy also contracts for underground storage capacity and deliverability from third parties in north east British Columbia, Alberta and the Pacific Northwest of the United States. On a combined basis, FortisBC Energy's Tilbury and Mount Hayes facilities, the contracted storage facilities, and other peaking arrangements can deliver up to 0.73 PJs per day of supply to FortisBC Energy on the coldest days of the heating season. The heating season typically occurs during the December through February period.

Off-System Sales

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

Under the GSMIP revenue sharing model, which is approved by the BCUC, FortisBC Energy can earn an incentive payment for mitigation activities. Historically, FortisBC Energy has earned approximately $1.2 million annually through GSMIP, while the remaining savings are credited back to customers through reduced rates. Subject to the BCUC's approval, FortisBC Energy earned an incentive payment of approximately $2.0 million in respect of the gas contract twelve months ended October 31, 2016.

The current GSMIP program was approved by the BCUC following a comprehensive review in 2011. In 2013, the BCUC approved an extension of the program until October 31, 2016. In August 2016, FortisBC Energy received approval from the Commission for a renewal of the GSMIP program effective November 1, 2016 through October 31, 2019.

Price-Risk Management Plan

FortisBC Energy engages in price-risk management activities to mitigate the impact on customer rates of fluctuations in natural gas prices. These activities include physical gas purchasing and storage strategies, as well as FortisBC Energy's current quarterly commodity rate-setting and deferral account mechanism.

During 2015, FortisBC Energy conducted a series of workshops with stakeholders to provide background and education and obtain feedback regarding FortisBC Energy's current price-risk management activities and possible strategies and options it could pursue in the future. Subsequently, FortisBC Energy filed the 2015 Price-Risk Management Application on December 23, 2015 with the BCUC which included FortisBC Energy's request to implement a medium-term hedging program and commodity rate-setting enhancements. On June 17, 2016, the BCUC approved FortisBC Energy's application. As of December 31, 2016, the market price targets and maximum volume limits were not reached and therefore the price risk strategies were not implemented.

Unbundling

A Customer Choice program at FortisBC Energy allows eligible commercial and residential customers a choice to buy their natural gas commodity supply from FortisBC Energy or directly from third-party marketers. FortisBC Energy continues to provide the delivery service of the natural gas to all its customers. For the year ended December 31, 2016, approximately 4% of eligible commercial customers and 3% of eligible residential customers participated in the program by purchasing their commodity supply from alternate providers.

FortisAlberta

FortisAlberta is a regulated electricity distribution utility operating in Alberta. Its business is the ownership and operation of regulated electricity distribution facilities that distribute electricity, generated by other market participants, from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 122,000 kilometres of distribution lines. Many of FortisAlberta's customers are located in rural and suburban areas around and between the cities of Edmonton and Calgary. FortisAlberta's distribution network serves approximately 549,000 customers, comprising residential, commercial, farm, oil and gas and industrial consumers, and met a peak demand of 2,581 MW in 2016.

Market and Sales

FortisAlberta's annual energy deliveries decreased from 17,132 GWh in 2015 to 16,788 GWh in 2016. Revenue was $572 million in 2016 compared to $563 million in 2015.

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

The following table compares the composition of FortisAlberta's 2016 and 2015 revenue and energy deliveries by customer class.

	Revenue (%)		GWh Deliveries (%) [(1)]	
	2016	2015	**2016**	2015
Residential	**31.0**	29.4	**18.1**	17.5
Large commercial, industrial and oil field	**20.7**	21.9	**60.1**	60.7
Farms	**13.2**	13.5	**7.9**	7.9
Small commercial	**12.0**	12.0	**8.1**	8.0
Small oil field	**8.8**	9.6	**5.4**	5.5
Other [(2)]	**14.3**	13.6	**0.4**	0.4
Total	**100.0**	100.0	**100.0**	100.0

(1) *GWh percentages exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries were 6,524 GWh in 2016 and 6,663 GWh in 2015, based on interim settlement that is expected to be finalized in May 2017, and consisted primarily of energy deliveries to large-scale industrial customers directly connected to the transmission grid.*

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

Franchise Agreements

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

FortisAlberta holds franchise agreements with 155 municipalities within its service area. The franchise agreement template includes a 10-year term with an option that will permit the agreement to automatically renew for up to two subsequent five-year terms. To date, FortisAlberta has converted over 90% of the municipalities within its service area to the new franchise agreement. The current 10-year terms will not expire until 2023 and beyond.

FortisBC Electric

FortisBC Electric is an integrated electric utility that owns hydroelectric generating plants, high voltage transmission lines, and a large network of distribution assets, all of which are located in the southern interior of British Columbia. FortisBC Electric serves approximately 170,000 customers and met a peak demand of 712 MW in 2016. FortisBC Electric's T&D assets include approximately 7,200 kilometres of T&D lines and 65 substations.

FortisBC Electric is also responsible for the operating, maintenance and management services at the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro; the 335-MW Waneta Expansion, owned by the Waneta Partnership between Fortis and CPC/CBT; the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT.

Market and Sales

FortisBC Electric has a diverse customer base composed of residential, commercial, industrial and municipal wholesale, and other industrial customers. Electricity sales were 3,119 GWh in 2016, compared to 3,116 GWh in 2015. Revenue increased to $377 million in 2016 from $360 million in 2015.

The following table compares the composition of FortisBC Electric's 2016 and 2015 revenue and electricity sales by customer class.

	Revenue (%)		GWh Sales (%)	
	2016	2015	**2016**	2015
Residential	44.6	45.3	40.4	40.2
Commercial	24.3	24.0	29.7	29.1
Wholesale	11.8	12.2	17.7	18.6
Industrial	8.2	8.3	12.2	12.1
Other (1)	11.1	10.2	-	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity, including revenue of FortisBC Pacific Holdings Inc. associated with non-regulated operating, maintenance and management services.*

Generation and Power Supply

FortisBC Electric meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. The company owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 225 MW, which provide approximately 48% of the company's energy needs and 29% of its peak capacity needs. FortisBC Electric meets the balance of its requirements through a portfolio of long-term and short-term PPAs.

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

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

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	256	BC Hydro
Waneta Dam	237	Teck Metals Ltd.
Waneta Expansion	335	Waneta Partnership
Kootenay River System	225	FortisBC Electric
Brilliant Dam	149	BPC
Brilliant Expansion	120	BEPC
Total	**1,902**	

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

FortisBC Electric's remaining electricity supply is acquired through short and long-term PPAs with a number of counterparties, including electricity produced by the Waneta Expansion, a hydroelectric project owned by the Waneta Partnership, which is 51% owned by Fortis and 49% owned by a subsidiary of CPC/CBT. During 2016, FortisBC Electric purchased capacity and energy from the market to meet its peak energy requirements and optimize its overall power supply portfolio. Spot market and contracted purchases provided approximately 8% of FortisBC Electric's energy supply requirements in 2016. FortisBC Electric's PPAs and market purchases have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Electric's electricity rates.

Eastern Canadian Electric Utilities

Eastern Canadian Electric Utilities are comprised of the operations of Newfoundland Power, Maritime Electric and FortisOntario.

Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 264,000 customers in approximately 600 communities. Newfoundland Power has installed generating capacity of 139 MW and met a peak demand of 1,367 MW in 2016. Newfoundland Power owns and operates approximately 12,000 kilometres of T&D lines.

Maritime Electric is an integrated electric utility and the principal distributor of electricity on PEI, serving approximately 79,000 customers, constituting approximately 90% of electricity consumers on PEI. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a New Brunswick Crown corporation, through various energy purchase agreements. Maritime Electric owns and operates generating plants with a combined capacity of 145 MW and met a peak demand of 265 MW in 2016. Maritime Electric owns and operates approximately 5,900 kilometres of T&D lines.

FortisOntario provides integrated electric utility service through its three operating utilities to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario also owns a 10% interest in three regional electric distribution companies serving approximately 40,000 customers. FortisOntario met a combined peak demand of 248 MW in 2016. FortisOntario owns and operates approximately 3,500 kilometres of T&D lines.

Market and Sales

Electricity sales attributable to the Eastern Canadian Electric Utilities were 8,374 GWh in 2016 compared to 8,403 GWh in 2015. Revenue was $1,063 million in 2016 compared to $1,033 million in 2015.

The following table compares the composition of revenue and electricity sales by customer class at Eastern Canadian Electric Utilities in 2016 and 2015.

	Revenue (%)		GWh Sales (%)	
	2016	2015	**2016**	2015
Residential	**56.8**	56.6	**56.9**	56.9
Commercial and Industrial	**39.5**	40.1	**43.0**	43.0
Other [(1)]	**3.7**	3.3	**0.1**	0.1
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Includes revenue from sources other than from the sale of electricity.*

Power Supply

Newfoundland Power

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

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

Newfoundland Hydro has a number of applications before the PUB for consideration, including a general rate application which will, amongst other things, establish wholesale rates for Newfoundland Power. The outcome of the general rate application is anticipated in the first half of 2017. Future changes in supply costs, including costs associated with the Muskrat Falls hydroelectric generation development and associated transmission assets, may increase electricity prices in a manner that adversely affects Newfoundland Power's sales.

Newfoundland Power experienced losses of electricity supply from Newfoundland Hydro in January 2013 and January 2014, which prevented Newfoundland Power from meeting all of its customers' requirements. The PUB is conducting an inquiry and hearing into these system supply issues and power interruptions. In September 2016 the PUB issued its report on the first phase of the inquiry regarding the adequacy and reliability of the Island Interconnected system until connection with the Muskrat Falls hydroelectric generation facility occurs. The report indicated that Newfoundland Power did not cause or contribute to the power outages. It also indicated significant concerns remain in relation to the adequacy and reliability of supply from Newfoundland Hydro. The second phase of the inquiry and hearing process is ongoing, which considers longer term issues associated with adequacy and reliability on the Island Interconnected system after interconnection with the Muskrat Falls hydroelectric generation facility.

Newfoundland Power operates 28 small generating facilities, which generate approximately 7% of the electricity sold by the company. Newfoundland Power's hydroelectric generating plants have a total capacity of 97 MW and its diesel plants and gas turbines have a total capacity of approximately 5 MW and 37 MW, respectively.

Maritime Electric

Maritime Electric purchased 77% of the electricity required to meet its customers' needs from NB Power in 2016. The balance was met through the purchase of wind energy produced on PEI by facilities owned by the PEI Energy Corporation and from company-owned on-Island generation. Maritime Electric's on-Island generation facilities are used primarily for peaking, submarine-cable loading issues and emergency purposes.

Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity: (i) a fixed-pricing contract with NB Power expiring February 28, 2019; and (ii) a transmission capacity contract with NB Power allowing Maritime Electric to reserve 30 MW of capacity to PEI expiring November 2032. As well, Maritime Electric has an Energy Purchase Agreement with NB Power expiring in February 2019.

Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau Nuclear Generating Station for the life of the unit and as part of its entitlement is required to pay its share of the capital and operating costs of the unit.

FortisOntario

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

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

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

Regulated Electric Utilities – Caribbean

The Corporation's Regulated Electric Utilities – Caribbean segment includes Caribbean Utilities, Fortis Turks and Caicos and the Corporation's 33% equity investment in Belize Electricity. Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. Caribbean Utilities is a public company traded on the TSX (TSX:CUP.U) and Fortis holds an approximate 60% controlling ownership interest in the utility as at December 31, 2016. Fortis Turks and Caicos is an integrated generation, transmission and distribution utility serving the Turks and Caicos Islands. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize. The results of Belize Electricity are not included in the description of this segment.

The Regulated Electric Utilities – Caribbean segment serves approximately 43,200 customers on Grand Cayman, Cayman Islands and certain islands in Turks and Caicos and met a peak demand of 143 MW in 2016. The utilities own and operate almost 1,400 kilometres of T&D lines, including 24 kilometres of submarine cable.

Market and Sales

Electricity sales of Regulated Electric Utilities – Caribbean were 837 GWh in 2016, compared to 802 GWh in 2015. Revenue was $301 million in 2016 compared with $321 million in 2015.

The following table compares the composition of revenue and electricity sales by customer class at the Regulated Electric Utilities – Caribbean for 2016 and 2015.

	Revenue (%)		GWh Sales (%)	
	2016	2015	**2016**	2015
Residential	**44.6**	42.9	**44.5**	43.0
Commercial and Industrial	**54.3**	56.2	**55.5**	57.0
Other [(1)]	**1.1**	0.9	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

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

Power Supply

Caribbean Utilities and Fortis Turks and Caicos rely upon in-house diesel-powered generation to produce electricity for their customers, with an installed generating capacity of 161 MW and 82 MW, respectively.

Caribbean Utilities is party to primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40%, respectively, of Caribbean Utilities' diesel fuel requirements for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2017 is 22.3 million imperial gallons. Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 14 million imperial gallons per annum.

In June 2016 Caribbean Utilities completed and commissioned a 39.7 MW diesel power plant, including two 18.5 MW diesel-generating units and a 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment. The project was completed on schedule and below budget at a cost of US$79 million.

Non-Regulated

Non-Regulated – Energy Infrastructure

The Corporation's Non-Regulated – Energy Infrastructure segment is primarily comprised of long-term contracted generation assets in British Columbia and Belize, and 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 Partnership, with CPC/CBT holding the remaining 49% interest. All of the output of the Waneta Expansion is sold to BC Hydro and FortisBC Electric under 40-year contracts. As described above, FortisBC Electric operates and maintains the Waneta Expansion.

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

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

Generating assets in Ontario are comprised of the operation of a 5-MW gas-powered cogeneration plant in Cornwall conducted through a wholly owned subsidiary of FortisOntario. All thermal energy output of this plant is sold to external third parties, while the electricity output is sold to Cornwall Electric.

In February 2016, the Corporation sold its 16-MW run-of-river Walden hydroelectric generating facility in British Columbia. The Corporation sold its non-regulated hydro generation assets in Upstate New York and Ontario in 2015.

Market and Sales

Energy sales from non-regulated energy infrastructure assets were 901 GWh in 2016 compared to 844 GWh in 2015. Revenue from energy sales, mainly at the Waneta Expansion and in Belize, was $193 million in 2016 compared to $107 million in 2015. Energy sales in 2016 were impacted by a full year's contribution from the Waneta Expansion. Revenue also included lease storage revenue at Aitken Creek, totaling $65 million from the date of acquisition in April 2016. Energy sales and revenue in 2015 were impacted by the completion of Waneta Expansion and the sale of the non-regulated hydro generation assets in Upstate New York and Ontario.

Non-Regulated – Non-Utility

The Corporation's Non-Regulated – Non-Utility segment previously included Fortis Properties. The Corporation completed the sale of the commercial real estate assets of Fortis Properties in June 2015 and the hotel assets of Fortis Properties in October 2015.

Corporate and Other

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

HUMAN RESOURCES

As of December 31, 2016, Fortis and its subsidiaries had more than 8,000 employees, with 52% in Canada, 44% in the USA and 4% in other countries. The following table provides the breakdown of full-time equivalent employees among the Corporation's subsidiaries and corporate office.

	Employees	Participation in a Collective Agreement	Union(s)	Current Collective Agreement Expiry Date(s)
Regulated Electric & Gas Utilities – United States				
ITC	660	None	-	-
UNS Energy	2,023	53%	IBEW	February 2017 [(1)] – June 2019
Central Hudson	992	59%	IBEW	April 2017
Regulated Gas & Electric Utilities – Canadian				
FortisBC Energy	1,644	70%	IBEW, COPE	March 2017 – March 2019
FortisAlberta	1,132	81%	UUWA	December 2017
FortisBC Electric	490	69%	IBEW, COPE	March 2017 – December 2018
Eastern Canadian	1,011	60%	IBEW, CUPE, Power Workers Union	September 2017 – December 2019
Regulated Electric Utilities – Caribbean [(2)]				
	372	None	-	-
Non-Regulated				
Energy Infrastructure [(3)]	51	None	-	-
Corporate and Other [(4)]				
	50	None	-	-
Total	8,425	56%	-	-

(1) *The collective agreement with IBEW Local No. 387, which covers both UNS Electric and UNS Gas in Santa Cruz County has been renegotiated with a tentative agreement that expires in February 2020. Management does not anticipate any issues with finalizing the agreement prior to expiration of the existing agreement.*

(2) *Excludes Belize Electricity.*

(3) *Includes employees at BECOL and ACGS. Energy Infrastructure operations in British Columbia and Ontario are staffed by employees of FortisBC Inc. and FortisOntario, respectively.*

(4) *Includes employees at Fortis Inc. and FAES.*

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings in respect of which the Corporation is or was a party, or in respect of which any of the Corporation's property is or was the subject during the year ended December 31, 2016, nor are there any such proceedings known to the Corporation to be contemplated, that involve a claim for damages exceeding 10% of the Corporation's current assets.

Information related to the Corporation's legal proceedings can be found in Note 34 of the Corporation's 2016 Audited Consolidated Financial Statements, which is incorporated herein by reference.

The Corporation's utilities primarily operate under a cost of service regulation and, in certain circumstances, performance-based rate-setting mechanisms, and are regulated by the regulatory body in their respective operating jurisdiction. There have not been any: (a) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2016; (b) any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; or (c) settlement agreements entered into by the Corporation before a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2016.

For information with respect to the nature of regulation and material regulatory decisions and applications associated with each of the Corporation's electric and gas utilities, refer to the "Regulatory Highlights" section of the Corporation's MD&A and to Note 8 of the Corporation's 2016 Audited Consolidated Financial Statements.

RISK FACTORS

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

CORPORATE SOCIAL RESPONSIBILITY

Social and Environmental Policies

The Corporation and its utilities each have a range of social and environmental policies, programs and practices. Fortis has a Code of Business Conduct and Ethics which sets out the Corporation's standards for the ethical conduct of its business, applicable to all of its directors, officers and employees, and to the extent feasible also to consultants, contractors and representatives of Fortis and each Fortis subsidiary.

In 2015, Fortis adopted a Diversity Policy that describes the principles underlying the Corporation's approach to diversity and its objectives with respect to diversity among its leadership team at the board and executive level. For further information on the Corporation's Diversity Policy, refer to the Corporation's Management Information Circular dated March 18, 2016.

Each of the operating subsidiaries are stand-alone entities responsible for implementing policies, programs and practices that adhere to the standards set forth in the Corporation's policies, while taking into account the jurisdiction and unique operating environment of the subsidiary. Social and environmental policies in place at the Corporation's utilities include, among others: a Code of Business Conduct and Ethics; Health, Safety, and Environmental Policies; Diversity Policies; Equal Opportunity Policies; Respectful Workplace, Workplace Harassment and Violence Policies; Disability Non-Discrimination Policies; and Accommodation Policies. More specifically, the Corporation's Environmental Statement requires subsidiaries to comply with all applicable laws and regulations relating to the protection of the environment, regularly conduct monitoring and audits of environmental management systems and seek feasible, cost-effective opportunities to decrease GHG emissions and increase renewable energy sources.

Environmental Regulation

The Corporation and its subsidiaries are subject to various federal, provincial, state and municipal laws, regulations and guidelines relating to the protection of the environment. Compliance with environmental laws, regulations and guidelines involve significant operating and capital costs. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are generally eligible for recovery in customer rates. There is no assurance, however, that all such costs will be recovered or that continued recovery in customer rates will be permitted.

The Corporation's regulated utilities consist primarily of transmission and distribution assets, which have minimal direct GHG emissions. The Corporation's GHG emissions come primarily from its generation assets, including emissions from UNS Energy's coal-fired generating assets in the States of Arizona and New Mexico. Due to the current uncertainties related to federal and state regulation of GHG emissions in the United States, the Corporation cannot predict the ultimate outcome of initiatives to regulate GHG emissions or the range of the potential impact. See the "Business Risk Management" section of the Corporation's MD&A. However, given the Corporation's diverse portfolio of assets and focus on delivering renewable energy to customers in a cost-effective manner, there are opportunities to decrease GHG emissions and lower the Corporation's exposure to any future GHG reduction requirements or carbon tax in the United States. The Corporation's utilities will continue to seek recovery of its prudently incurred compliance costs through appropriate regulatory mechanisms. There is no assurance, however, that all such costs would be recovered.

Environmental Contingencies

TEP

San Juan Generating Station. In February 2013, WEG filed a Petition for Review in the U.S. District Court for the District of Colorado against the OSM challenging federal administrative decisions affecting seven different mines in four states issued at various times from 2007 through 2012. In its petition, WEG challenges several unrelated mining plan modification approvals, which were each separately approved by the OSM. Of the fifteen claims for relief in the WEG petition, two concern SJCC's San Juan mine. WEG's allegations concerning the San Juan mine arise from the OSM administrative actions in 2008. WEG alleges various NEPA violations against the OSM, including, but not limited to, the OSM's alleged failure to provide requisite public notice and participation, alleged failure to analyze certain environmental impacts, and alleged reliance on outdated and insufficient documents. WEG's petition seeks various forms of relief, including a finding that the federal defendants violated the NEPA by approving the mine plans, voiding, reversing, and remanding the various mining modification approvals, enjoining the federal defendants from re-issuing the mining plan approvals for the mines until compliance with the NEPA has been demonstrated, and enjoining operations at the seven mines. SJCC intervened in this matter. SJCC was granted its motion to sever its claims from the lawsuit and transfer venue to the U.S. District Court for the District of New Mexico, where this matter is now proceeding. On July 18, 2016, the federal defendants filed a motion asking that the matter be voluntarily remanded to the OSM so the OSM may prepare a new environmental impact statement under the NEPA regarding the impacts of the San Juan Mine mining plan approval. In August 2016, the court issued an order granting the federal defendants' motion for remand to conduct further environmental analysis and complete an environmental impact statement by August 31, 2019. The order provided that the OSM's decision approving the mining plan will remain in effect during this process. The order further provides that if the EIS is not completed by August 31, 2019, then an order vacating the approved mine plan will become immediately effective, absent further court order. TEP cannot currently predict the outcome of this matter or estimate the value of any potential impact.

Four Corners Generating Station. On April 20, 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Arizona against the OSM and other federal agencies under the Endangered Species Act alleging that the OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with a federal environmental review were not in accordance with applicable law. The environmental review was undertaken as part of the U.S. Department of the Interior's review process necessary to allow for the effectiveness of lease amendments and related rights-of-way renewals for Four Corners. This review process also required separate environmental impact evaluations under the NEPA and culminated in the issuance of a Record of Decision justifying the agency action extending the life of Four Corners and the adjacent Navajo mine. In addition, the lawsuit alleges that these federal agencies violated both the Endangered Species Act and the NEPA in providing the federal approvals necessary to extend operations at Four Corners and the Navajo mine past July 6, 2016. The lawsuit seeks various forms of relief, including a finding that the federal defendants violated the Endangered Species Act and the NEPA by issuing the Record of Decision, setting aside and remanding the Biological Opinion and Record of Decision, and enjoining the federal defendants from authorizing any elements of the Four Corners and Navajo mine pending compliance with NEPA. In July 2016, the defendants answered the complaint and APS, the operator of Four Corners, filed a motion to intervene in this matter. APS' motion was granted in August 2016. Briefing on the merits is expected to extend through May 2017. NTEC, the company that owns the Navajo Mine, filed a motion to intervene in September 2016 for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. TEP cannot currently predict the outcome of this matter or estimate the value of any potential impact.

Mine Reclamation at Generation Facilities Not Operated by TEP. TEP pays ongoing reclamation costs related to coal mines that supply generation facilities in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US$61 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The mine reclamation liability recorded as at December 31, 2016 was US$25 million and represents the present value of the estimated future liability.

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

Central Hudson

Former MGP Facilities. Central Hudson has remediation costs associated with former MGPs that it and its predecessors owned and/or operated at seven sites in Central Hudson's franchise territory. The New York State Department of Environmental Conservation, which regulates the timing and extent of remediation of MGP sites in New York State, has requested that Central Hudson investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-Up Agreement or Brownfield Clean-Up Agreement. As at December 31, 2016, Central Hudson has recognized an obligation of US$73 million in respect of site investigation and remediation. As approved by the New York State Public Service Commission, Central Hudson is currently permitted to recover MGP site investigation and remediation costs in customer rates.

CAPITAL STRUCTURE AND DIVIDENDS

Description of Capital Structure

The authorized share capital of the Corporation consists of an unlimited number of Common Shares without nominal or par value, an unlimited number of First Preference Shares without nominal or par value, and an unlimited number of Second Preference Shares without nominal or par value.

As at February 15, 2017, the Corporation had issued and outstanding 401.6 million common shares; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M.

For a summary of the terms and conditions of the Corporation's authorized securities, and trading information for the Corporation's publicly listed securities, refer to Exhibit "A" and Exhibit "B" of this 2016 Annual Information Form.

Dividends and Distributions

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

In September 2016, Fortis increased its dividend per common share 6.7% to $0.40 per share, or $1.60 on an annualized basis. In December 2016 the Board declared a first quarter 2017 dividend on the Common Shares of $0.40 per share and on the First Preference Shares, Series F, G, H, I, J, K and M in accordance with the applicable annual prescribed rate. The first quarter dividends on the Common Shares and the First Preference Shares, Series F, G, H, I, J, K and M are to be paid on March 1, 2017 to holders of record as of February 16, 2017.

Fortis has targeted average annual dividend growth of 6% through 2021. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure program, and Management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

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

	2016	2015	2014
Common Shares	**$1.5500**	$1.4300	$1.3000
First Preference Shares, Series E (1)	**$0.6126**	$1.2250	$1.2250
First Preference Shares, Series F (2)	**$1.2250**	$1.2250	$1.2250
First Preference Shares, Series G (3)	**$0.9708**	$0.9708	$0.9708
First Preference Shares, Series H (4)	**$0.6250**	$0.7344	$1.0625
First Preference Shares, Series I (5)	**$0.4874**	$0.3637	-
First Preference Shares, Series J (2)	**$1.1875**	$1.1875	$1.1875
First Preference Shares, Series K (6)	**$1.0000**	$1.0000	$1.0000
First Preference Shares, Series M (7)	**$1.0250**	$1.0250	$0.4613

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

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

(3) *The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.*

(4) *The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020.*

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

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

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

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on Common and 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.

Debt Covenant Restrictions on Dividend Distributions

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

The Corporation has a $1.3 billion unsecured committed revolving corporate credit facility, maturing in July 2021, that is available for general corporate purposes. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 65% at any time. In connection with the acquisition of ITC Holdings, the Corporation entered into an unsecured equity bridge credit facility that also contains a substantially similar covenant.

As at December 31, 2016 and 2015, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

Prior Sales

On October 4, 2016, the Corporation issued US$500 million aggregate principal amount of 2.100% unsecured notes due 2021 and US$1.5 billion aggregate principal amount of 3.055% unsecured notes due 2026. On December 12, 2016, the Corporation issued $500 million aggregate principal amount of 2.85% unsecured notes due December 12, 2023. The notes issued by Fortis in 2016 are not listed on a stock exchange or publicly traded.

Credit Ratings

Securities issued by Fortis and its utilities, that are currently rated, are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's debt credit ratings as at February 15, 2017.

Company	Security	DBRS	S&P	Moody's
Fortis (1) (2)	Unsecured Debt	BBB (high) - Stable	BBB+, Stable	Baa3 , Stable
Caribbean Utilities (3) (4)	Senior Unsecured Debt	A (low), Stable	A-, Stable	-
Central Hudson (3) (5) (6)	Unsecured Debt	-	A-, Stable	A2, Stable
FortisBC Energy	Unsecured Debt	A, Stable		A3, Stable
FortisAlberta (3) (4)	Senior Unsecured Debt	A (low), Stable	A-, Stable	-
FortisBC Electric	Secured Debt	A (low), Stable	-	-
	Unsecured Debt	A (low), Stable		Baa1, Stable
Fortis Turks and Caicos	Senior Unsecured Debt	-	BBB, Stable	-
ITC Holdings	Senior Unsecured Debt	-	BBB+, Stable	Baa2, Stable
	Commercial Paper		A-2, Stable	Prime-2, Stable
ITC Great Plains	First Mortgage Bonds	-	A, Stable	A1, Stable
ITC Midwest	First Mortgage Bonds	-	A, Stable	A1, Stable
ITCTransmission	First Mortgage Bonds	-	A, Stable	A1, Stable
Maritime Electric (3) (7)	Senior Secured Debt	-	A, Stable	-
METC	Senior Secured Debt	-	A, Stable	A1, Stable
Newfoundland Power	First Mortgage Bonds	A, Stable	-	A2, Stable
TEP (3) (8)	Unsecured Debt	-	BBB+, Stable	-
	Senior Unsecured Debt		-	A3, Stable
UNS Energy	Senior Secured Debt	-	-	Baa1, Stable

(1) *In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P affirmed the Corporation's corporate credit rating of A-, revised its unsecured debt credit rating to BBB+ from A-, and revised its outlook on the Corporation to negative from stable. Similarly, in February 2016 DBRS placed the Corporation's corporate credit rating under review with negative implications. In October 2016, following the completion of the acquisition of ITC, DBRS revised the Corporation's unsecured debt credit rating to BBB (high) from A (low) and revised its outlook to stable from under review with negative implications, and S&P affirmed the Corporation's long-term corporate and unsecured debt credit ratings and revised its outlook to stable from negative.*

(2) *In September 2016, Moody's commenced rating Fortis and assigned the Corporation an issuer credit rating of Baa3 and an unsecured debt credit rating of Baa3, both with a stable outlook.*

(3) *In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P revised its outlook on TEP, Central Hudson, FortisAlberta, Maritime Electric and Caribbean Utilities to negative from stable.*

(4) *In October 2016, following the completion of the acquisition of ITC, S&P affirmed FortisAlberta's and Caribbean Utilities' debt credit ratings at 'A-' and revised its outlook to stable from negative.*

(5) *In June 2016, S&P downgraded Central Hudson's senior unsecured debt rating to 'A-' from 'A' and revised its outlook to stable from negative.*

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

(7) *In March 2016, S&P affirmed Maritime Electric's secured debt credit rating at 'A' and revised its outlook to stable from negative.*

(8) *In July 2016, S&P affirmed TEP's unsecured debt credit rating at 'BBB+' and revised its outlook to stable from negative.*

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

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

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

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

The Corporation and/or each of its currently rated utilities pay DBRS, Fitch, S&P and/or Moody's an annual monitoring fee and a one-time fee in connection with each rated issuance. In 2016 and 2015 Fortis also paid fees to S&P and Moody's in respect of certain advisory services provided in connection with the acquisition of ITC.

DIRECTORS AND OFFICERS

The Board has governance guidelines which cover various items, including director tenure. The governance guidelines provide that Directors of the Corporation are to be elected for a term of one year and, except in appropriate circumstances determined by the Board, be eligible for re-election until the annual meeting of shareholders next following the date on which they achieve age 72 or the 12th anniversary of their initial election to the Board.

The following table sets out the name, province or state, and country of residence of each of the Directors of Fortis as of February 15, 2017, and indicates their principal occupations within the five preceding years. Each Director's current term expires at the close of the May 4, 2017 annual meeting of shareholders.

Name and Place of Residence	Committees			Director Since	Principal Occupations Within Five Preceding Years
	Audit	Governance and Nominating	Human Resources		
TRACEY C. BALL Alberta, Canada	X			May 2014	Ms. Ball, 59, a Corporate Director, was Executive Vice President and Chief Financial Officer of Canadian Western Bank Group from 2006 until her retirement in September 2014. Ms. Ball serves as a director of FortisAlberta and is Chair of that Board.
PIERRE J. BLOUIN Quebec, Canada		X	X	May 2015	Mr. Blouin, 58, a Corporate Director, was Chief Executive Officer of Manitoba Telecom Services, Inc. from 2005 until his retirement in December 2014.
PETER E. CASE Ontario, Canada	C	X		May 2005	Mr. Case, 62, a Corporate Director, has been Chair of the Audit Committee since March 2011.
MAURA J. CLARK New York, USA	X	X		May 2015	Ms. Clark, 58, a Corporate Director, retired from Direct Energy, a subsidiary of Centrica plc, in March 2014 where she was President of Direct Energy Business from 2007.
MARGARITA K. DILLEY Virginia, USA	X			May 2016	Ms. Dilley, 59, a Corporate Director, has served as a director of CH Energy Group since 2004 and serves as Chair of that Board.
IDA J. GOODREAU British Columbia, Canada		X	C	May 2009	Ms. Goodreau, 65, a Corporate Director, has served as a director of FortisBC Energy and FortisBC Inc. since 2007 and 2010, respectively. Ms. Goodreau serves as Chair of the Governance Committee of FortisBC Energy and FortisBC Inc.
DOUGLAS J. HAUGHEY Alberta, Canada	X	X	X	May 2009	Mr. Haughey, 60, a Corporate Director, was Chief Executive Officer of The Churchill Corporation from August 2012 through May 2013. From 2010 through April 2012, he served as President and Chief Executive Officer of Provident Energy Ltd. Mr. Haughey served as a director of FortisAlberta from 2010 and as Chair of that Board from 2013 until April 2016. Mr. Haughey was appointed Chair of the Board in September 2016.
R. HARRY McWATTERS British Columbia, Canada		X		May 2007	Mr. McWatters, 71, is the President of Vintage Consulting Group Inc., Harry McWatters Inc., and TIME Estate Winery, all of which are engaged in various aspects of the British Columbia wine industry.
RONALD D. MUNKLEY Ontario, Canada		C	X	May 2009	Mr. Munkley, 70, a Corporate Director, retired in 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets.
DAVID G. NORRIS Newfoundland and Labrador, Canada	X	X	X	May 2005	Mr. Norris, 69, a Corporate Director, was a financial and management consultant from 2001 until his retirement in December 2013. He served as Chair of the Board from December 2010 to September 2016.
BARRY V. PERRY Newfoundland and Labrador, Canada				January 2015	Mr. Perry, 52, is President and Chief Executive Officer of the Corporation. Prior to his current position at Fortis, he served as President from June 30, 2014 to December 31, 2014 and prior to that served as Vice President, Finance and Chief Financial Officer of the Corporation. Mr. Perry serves on the Boards of FortisBC Energy, FortisBC Inc., UNS and ITC Holdings. Mr. Perry was appointed to the Board concurrent with his appointment as President and Chief Executive Officer of the Corporation. Mr. Perry is not a member of any committees as he is not independent as he is the President and Chief Executive Officer of the Corporation.
JO MARK ZUREL Newfoundland and Labrador, Canada			X	May 2016	Mr. Zurel, 52, is President of Stonebridge Capital Inc., a private investment company. Mr. Zurel served as a director of Newfoundland Power from January 2008 to July 2016.

The following table sets out the name, province or state, and country of residence of each of the executive officers of Fortis as of December 31, 2016, and indicates the office held and principal occupations of the executive officers during the five preceding years.

Name and Place of Residence	Office	Principal Occupation During the Five Preceding Years
BARRY V. PERRY Newfoundland and Labrador, Canada	President and Chief Executive Officer	Mr. Perry was appointed President and Chief Executive Officer, effective January 1, 2015. Mr. Perry became President of Fortis effective June 30, 2014. From 2004 to the time of his appointment as President, Mr. Perry served as Vice President, Finance and Chief Financial Officer of Fortis.
KARL W. SMITH Newfoundland and Labrador, Canada	Executive Vice President, Chief Financial Officer	Mr. Smith was appointed Executive Vice President, Chief Financial Officer, effective June 30, 2014. From 2007 to the time of such appointment, Mr. Smith served as President and Chief Executive Officer of FortisAlberta.
NORA M. DUKE Newfoundland and Labrador, Canada	Executive Vice President, Corporate Services and Chief Human Resource Officer	Ms. Duke was appointed Executive Vice President, Corporate Services and Chief Human Resource Officer, effective August 1, 2015. From 2008 to the time of such appointment, Ms. Duke served as President and Chief Executive Officer of Fortis Properties.
JAMES P. LAURITO Florida, USA	Executive Vice President, Business Development	Mr. Laurito was appointed Executive Vice President, Business Development, effective April 1, 2016. From 2010 to the time of such appointment, Mr. Laurito served as President and Chief Executive Officer of Central Hudson.
EARL A. LUDLOW Newfoundland and Labrador, Canada	Executive Vice President, Eastern Canadian and Caribbean Operations	Mr. Ludlow was appointed Executive Vice President, Eastern Canadian and Caribbean Operations, effective August 1, 2014. From 2007 to the time of such appointment, Mr. Ludlow served as President and Chief Executive Officer at Newfoundland Power.
DAVID C. BENNETT Newfoundland and Labrador, Canada	Executive Vice President, Chief Legal Officer and Corporate Secretary	Mr. Bennett was appointed Executive Vice President, Chief Legal Officer and Corporate Secretary, effective May 9, 2016 and, prior thereto, served as Vice President, Chief Legal Officer and Corporate Secretary from September 19, 2014. Mr. Bennett served as Vice President, Operations Support, General Counsel and Corporate Secretary from 2013 until his appointment with Fortis and Vice President, General Counsel and Corporate Secretary for FortisBC Inc., FortisBC Energy and FHI from 2010 to 2013.
JANET A. CRAIG Newfoundland and Labrador, Canada	Vice President, Investor Relations	Ms. Craig was appointed Vice President, Investor Relations, effective October 1, 2015. Ms. Craig served as Senior Vice President, Investor Relations of Loblaws Companies Limited from 2013 to 2015, and served as Vice President, Investor Relations of Nexen Inc. from 2011 to 2013.
KAREN J. GOSSE Newfoundland and Labrador, Canada	Vice President, Planning and Forecasting	Ms. Gosse was appointed Vice President, Planning and Forecasting, effective November 1, 2015. Ms. Gosse served as Vice President, Finance, and Chief Financial Officer of Fortis Properties from 2013 until her appointment with Fortis and Manager, Financial Reporting of Fortis from 2005 to 2013.
JAMES D. SPINNEY Newfoundland and Labrador, Canada	Vice President, Treasurer	Mr. Spinney was appointed Vice President, Treasurer, effective March 20, 2013. From 2002 to the time of such appointment, Mr. Spinney served as Manager, Treasury of Fortis.
JAMIE D. ROBERTS Newfoundland and Labrador, Canada	Vice President, Controller	Mr. Roberts was appointed Vice President, Controller, effective March 20, 2013. From 2008 to the time of such appointment, Mr. Roberts served as Vice President, Finance and Chief Financial Officer of Fortis Properties.

As at December 31, 2016, the directors and executive officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 704,181 Common Shares, representing 0.2% of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

AUDIT COMMITTEE

Members

The members of the Corporation's audit committee are Peter E. Case (Chair), Tracey C. Ball, Maura J. Clark, Margarita K. Dilley, Douglas J. Haughey and David G. Norris.

The Board has determined that each of the Audit Committee members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a member's independent judgment as more particularly described in Multilateral Instrument 52-110 - *Audit Committees* and in accordance with the independence requirements set forth in Sections 303A.01 and 303A.07 of the NYSE corporate governance rules. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's 2016 Audited Consolidated Financial Statements.

The Board has determined that Tracey C. Ball and Maura J. Clark are the Corporation's "audit committee financial experts" within the meaning of Item 407(d) of Regulation S-K under the US Securities Act and have the required financial experience required by the NYSE corporate governance rules.

The Audit Committee Mandate is attached as Exhibit "C" to this 2016 Annual Information Form.

Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2016, the Audit Committee was composed of the following persons.

Committee Member	Relevant Education and Experience
PETER E. CASE *(Chair)*	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He holds a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
TRACEY C. BALL	Ms. Ball retired in September 2014 as Executive Vice President and Chief Financial Officer of Canadian Western Bank Group. Ms. Ball has served on several private and public sector boards, including the Province of Alberta Audit Committee and the Financial Executives Institute of Canada. She graduated from Simon Fraser University with a Bachelor of Arts (Commerce). She is a member of the Canadian Chartered Professional Accountants of Canada, the Institute of Chartered Accountants of Alberta, and the Association of Chartered Professional Accountants of British Columbia. She holds an ICD.D designation from the Institute of Corporate Directors.
MAURA J. CLARK	Ms. Clark retired from Direct Energy, a subsidiary of Centrica plc, in March 2014 where she was President of Direct Energy Business, a leading energy retailer in Canada and the United States. Previously Ms. Clark was Executive Vice President of North American Strategy and Mergers and Acquisitions for Direct Energy. Ms. Clark's prior experience includes investment banking and serving as Chief Financial Officer of an independent oil refining and marketing company. Ms. Clark graduated from Queen's University with a Bachelor of Arts in Economics. She is a member of the Association of Chartered Professional Accountants of Ontario.
MARGARITA K. DILLEY	Ms. Dilley retired from ASTROLINK International LLC in 2004, an international wireless broadband telecommunications company, where she was Vice President and Chief Financial Officer. Ms. Dilley's prior experience includes serving as Director, Strategy & Corporate Development as well as Treasurer for Intelsat. Ms. Dilley graduated from Cornell University with a Bachelor of Arts, from Columbia University with a Master of Arts and from Wharton Graduate School, University of Pennsylvania with an MBA.
DOUGLAS J. HAUGHEY	Mr. Haughey, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation. Prior to that, he served as President and Chief Executive Officer of Provident Energy Ltd. and held several executive roles with Spectra Energy and predecessor companies. He graduated from the University of Regina with a Bachelor of Business Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors.
DAVID G. NORRIS	Mr. Norris was a financial and management consultant from 2001 until his retirement in December 2013. Prior to that he was Executive Vice President, Finance and Business Development of Fishery Products International Limited. He holds a Bachelor of Commerce, Honours, from Memorial University of Newfoundland and an MBA from McMaster University.

Pre-Approval Policies and Procedures

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

External Auditor Service Fees

Fees incurred by the Corporation for work performed by Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related, tax, and non-audit services were as follows.

Ernst & Young LLP	2016	2015
Audit Fees	5,884	5,223
Audit-Related Fees	1,727	870
Tax Fees	332	475
Non-Audit Fees	-	-
Total	**7,943**	6,568

Audit fees were higher in 2016 than in 2015, mainly due to the increasing size and complexity of Fortis. Audit-related fees consisted mainly of assurance services provided in relation to the Corporation's readiness assessment with respect to the *Sarbanes-Oxley Act of 2002,* SEC registration and the acquisition of ITC and debt offerings. Tax fees consisted of tax surplus verification in the Caribbean and other tax services. Ernst & Young LLP did not provide any non-audit services in 2015 or 2016.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar in Canada for the Common Shares and First Preference Shares of Fortis is Computershare Trust Company of Canada in Montréal and Toronto.

The co-transfer agent and co-registrar in the United States for the Common Shares is Computershare Trust Company, N.A. in Canton, MA, Jersey City, NJ and College Station, TX.

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

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

AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Professional Accountants, Fortis Place, Suite 800, 5 Springdale Street, St. John's, NL, A1E 0E4. The consolidated financial statements of the Corporation for the fiscal year ended December 31, 2016 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation, and that they are independent accountants with respect to the Corporation under all relevant U.S. professional and regulatory standards.

The auditors of ITC are Deloitte & Touche LLP, located in Detroit, Michigan. Deloitte & Touche LLP audited the consolidated financial statements and financial statement schedule of ITC as at December 31, 2015 and December 31, 2014 and for the years ended December 31, 2015, 2014 and 2013 together with the notes thereto and the auditor's report thereon dated February 25, 2016, which are included in the Business Acquisition Report and the Corporation's Management Information Circular dated March 18, 2016. Deloitte & Touche LLP, certified public accountants, are independent with respect to ITC within the meaning of the US Securities Act and the applicable rules and regulations thereunder adopted by the SEC and the Public Company Accounting Oversight Board.

INTERESTS OF EXPERTS

Goldman, Sachs & Co. provided a fairness opinion to the Corporation which is included in the Corporation's Management Information Circular dated March 18, 2016. Goldman, Sachs & Co. and its affiliates own beneficially, directly or indirectly, less than 1% of the securities of Fortis or any of its associates or affiliates.

ADDITIONAL INFORMATION

Additional financial information is provided in the Corporation's MD&A and 2016 Audited Consolidated Financial Statements, which are incorporated herein by reference. These documents and additional information relating to the Corporation can be found on the Corporation's website at www.fortisinc.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated on or about March 18, 2016 for the May 5, 2016 annual meeting of shareholders.

Requests for additional copies of the above-mentioned documents, as well as this 2016 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.

EXHIBIT A: Summary of Terms and Conditions of Authorized Securities

Common Shares

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

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

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

Preference Shares

First Preference Shares

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

Issuance in Series

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

Priority

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

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

Voting

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

Redemption

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

Modification

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

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

First Preference Shares Authorized

On September 1, 2016, the 7,993,500 First Preference Shares, Series E were redeemed by the Corporation. The following table summarizes the series of first preference shares as of February 15, 2017.

Series	Authorized	Issued and Outstanding	Annual Dividend ($)	Earliest Redemption and/or Conversion Option Date	Redemption Value ($) [1]	Right to Convert on a One for One Basis
F	5,000,000	5,000,000	1.2250	December 1, 2011	25.00	-
G	9,200,000	9,200,000	0.9708 [2]	September 1, 2013 [3]	25.00	-
H	7,024,846	7,024,846	0.6250 [2]	June 1, 2015 [3]	25.00	Series I [3]
I	2,975,154	2,975,154	- [4]	June 1, 2015	25.50 [5]	Series H [3]
J	8,000,000	8,000,000	1.1875	December 1, 2017	26.00 [5]	-
K	10,000,000	10,000,000	1.0000 [2]	March 1, 2019 [3]	25.00	Series L [3]
L	12,000,000	-	- [4]	March 1, 2024	-	Series K [3]
M	24,000,000	24,000,000	1.0250 [2]	December 1, 2019 [3]	25.00	Series N [3]
N	24,000,000	-	- [4]	December 1, 2024	-	Series M [3]

(1) *Plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.*

(2) *On the redemption and/or conversion option date and each five-year anniversary thereafter, holders will be entitled to a reset of the dividend per share at a rate 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 2.13% (Series G), 1.45% (Series H), 2.05% (Series K), or 2.48% (Series M).*

(3) *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 preference shares of a specified series. If on any conversion option date the Corporation determines there would be less than 1,000,000 cumulative redeemable first preference shares of a specified series outstanding, such remaining shares of that series will be automatically converted into an equal number of cumulative redeemable preference shares of the specified series.*

(4) *After the redemption and conversion option dates, holders will be entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board, in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be reset every quarter based on the then current three month Government of Canada Treasury Bill rate plus 1.45% (Series I), 2.05% (Series L) and 2.48% (Series N).*

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

Second Preference Shares

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

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

EXHIBIT B: MARKET FOR SECURITIES

Common Shares

The Common Shares are traded on the TSX in Canada, and on the NYSE in the United States of America under the symbol FTS. The following table sets forth the reported high and low trading prices and trading volumes, on a monthly basis for the year ended December 31, 2016, for the Common Shares on the TSX and NYSE in Canadian Dollars and U.S. Dollars, respectively.

2016 Trading Prices and Volumes – Common Shares						
	TSX			NYSE [1]		
Month	High ($)	Low ($)	Volume	High (US$)	Low (US$)	Volume
January	40.71	35.79	15,310,648	-	-	-
February	41.58	35.53	42,973,318	-	-	-
March	41.08	37.74	24,278,066	-	-	-
April	41.09	38.52	16,625,820	-	-	-
May	41.48	39.50	19,329,553	-	-	-
June	43.91	40.78	20,791,983	-	-	-
July	44.87	42.79	16,617,319	-	-	-
August	43.75	40.99	16,936,055	-	-	-
September	42.83	40.32	18,057,520	-	-	-
October	44.22	40.13	55,424,615	33.250	32.000	2,540,021
November	44.27	39.58	28,724,405	33.030	29.930	1,801,178
December	41.94	39.83	18,921,785	31.353	30.250	800,296

(1) *The Common Shares commenced trading on the NYSE on October 14, 2016.*

Preference Shares

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

The following tables set forth the reported high and low trading prices and volumes for the First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M on a monthly basis for the year ended December 31, 2016.

2016 Trading Prices and Volumes – First Preference Shares						
	First Preference Shares, Series E [1]			First Preference Shares, Series F		
Month	High ($)	Low ($)	Volume	High ($)	Low ($)	Volume
January	25.40	25.16	447,669	23.39	20.70	71,898
February	25.39	24.98	195,875	22.50	21.25	72,699
March	25.21	25.03	910,051	22.75	21.41	68,513
April	25.29	25.13	260,444	23.65	22.43	64,624
May	25.44	25.01	45,965	23.98	22.99	35,996
June	25.38	25.10	91,909	24.10	23.01	42,356
July	25.49	25.21	251,488	25.12	23.51	119,301
August	25.31	25.28	801,488	25.40	24.68	44,020
September	-	-	-	24.95	24.46	62,489
October	-	-	-	24.80	24.05	53,777
November	-	-	-	24.70	22.82	99,066
December	-	-	-	23.21	22.07	113,559

Month	First Preference Shares, Series G High ($)	Low ($)	Volume	First Preference Shares, Series H High ($)	Low ($)	Volume
January	18.40	13.67	183,048	14.75	11.62	114,195
February	16.40	13.80	128,071	13.24	10.72	245,359
March	16.35	14.15	88,313	12.90	10.80	262,353
April	17.80	16.03	117,620	13.88	12.81	155,271
May	17.47	15.98	74,399	13.91	12.51	323,457
June	17.47	16.04	367,192	14.41	13.15	70,281
July	18.20	16.63	90,198	14.38	13.65	42,089
August	19.14	17.76	113,488	14.54	13.54	89,971
September	18.25	17.32	163,254	14.16	13.25	280,831
October	18.67	17.37	239,666	14.34	13.86	104,354
November	18.68	17.30	329,941	14.44	13.24	218,665
December	18.74	17.34	372,425	14.19	13.25	118,491

Month	First Preference Shares, Series I High ($)	Low ($)	Volume	First Preference Shares, Series J High ($)	Low ($)	Volume
January	12.56	10.35	38,209	22.66	19.15	109,984
February	10.74	8.90	45,475	21.84	20.45	84,608
March	10.85	9.17	36,170	21.88	20.82	213,627
April	12.00	10.50	38,797	22.76	21.70	62,788
May	12.04	11.25	46,678	23.17	22.22	63,674
June	12.16	11.62	72,197	23.52	22.27	59,206
July	12.41	12.00	20,709	24.22	22.80	347,487
August	12.85	11.88	32,400	24.49	23.70	100,536
September	12.13	11.58	52,530	24.27	23.61	236,018
October	13.04	12.05	89,636	24.27	23.60	393,068
November	12.49	11.99	196,806	24.08	22.15	117,718
December	12.84	12.05	135,559	22.62	21.60	313,813

Month	First Preference Shares, Series K High ($)	Low ($)	Volume	First Preference Shares, Series M High ($)	Low ($)	Volume
January	19.02	14.77	176,736	20.90	15.94	304,778
February	16.50	14.35	111,411	18.48	15.30	586,706
March	16.66	14.59	91,313	18.56	15.97	564,271
April	17.95	16.25	77,469	20.36	18.14	498,847
May	17.56	16.59	139,343	19.99	18.00	386,165
June	17.82	16.60	148,499	19.98	18.06	300,512
July	18.25	16.90	259,099	19.98	18.57	186,597
August	19.19	17.91	112,893	20.87	19.71	487,473
September	18.26	17.65	125,371	20.60	19.42	276,502
October	18.32	16.42	283,093	19.98	19.09	291,230
November	18.57	17.11	270,995	20.68	19.15	632,212
December	18.46	16.98	402,591	20.50	18.85	1,028,422

(1) *The Corporation redeemed all of the First Preference Shares, Series E on September 1, 2016.*

EXHIBIT C: AUDIT COMMITTEE MANDATE

A. Objective

The Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

B. Definitions

In this mandate:

"**AIF**" means the Annual Information Form filed by the Corporation;

"**Committee**" means the Audit Committee appointed by the Board pursuant to this mandate;

"**Board**" means the board of directors of the Corporation;

"**Corporation**" means Fortis Inc.;

"**Director**" means a member of the Board;

"**Financial Expert**" shall have the meaning set forth in Section 407 of Sarbanes-Oxley Act of 2002;

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

"**External Auditor**" means the firm of chartered professional accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

"**Independent**" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in National Instrument 52-110, and in accordance with the independent requirements set forth in Sections 303A.02 and 303A.07 of the New York Stock Exchange Listed Company Manual;

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

"**Management**" means the senior officers of the Corporation;

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

"**Member**" means a Director appointed to the Committee.

C. Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors, each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall designate one or more Members as a Financial Expert.

4. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call of (i) of the Chair of the Committee, or (ii) of any two (2) Members, or (iii) of the External Auditor.

5. The President and Chief Executive Officer, the Executive Vice President, Chief Financial Officer, the External Auditor and the Internal Auditor, shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

6. A quorum at any meeting of the Committee shall be three (3) Members.

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

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

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

D. Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for the selection, implementation and maintenance of appropriate accounting and financial reporting principles and policies and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor, including any non-audit services provided by the External Auditor. The Committee shall pre-approve all non-audit services provided by the External Auditor, including specific preapproval of internal control-related services based on PCAOB Rule 3525, and shall receive certain disclosure, documentation and discussion of non-prohibited tax services by the External Auditor based on PCAOB Rule 3524.

1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External Auditor. The Committee shall oversee the work of the External Auditor and resolve any disagreements between Management and the External Auditor.

1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in Canadian Auditing Standard – 260.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements together with notes thereto, the interim MD&A and earnings media release on behalf of the Board and shall review any earnings guidance for approval by the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any offerings and documents relating to any offerings, including any prospectus or any other offering document and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

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

2.7. The Committee shall review and approve all related-party transactions required to be disclosed according to US GAAP, and discuss with management the business rationale for the transactions and whether appropriate disclosures have been made.

2.8 The Committee shall be responsible for the oversight of the Internal Auditor.

2.9 The Committee shall monitor and report on the development of an enterprise risk management program for the Corporation.

2.10 The Committee shall prepare such periodic disclosure documents as requested by regulators or that may be required by law.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing;

3.2. Derivative Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring from Independent Auditing Firms Policy;

3.5. Policy on the Role of the Internal Audit Function;

3.6. Disclosure Policy; and

3.7. Any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statements; and oversight of the internal audit function.

4. Retaining and Compensating Advisors

The Committee shall have the sole authority to engage independent counsel and any other advisors as the Committee may deem appropriate in its sole discretion and to set the compensation for any advisors employed by the Committee. The Committee shall not be required to obtain the approval of the Board in order to retain or compensate such consultants or advisors.

E. Reporting

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

F. Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

2. The Committee shall retain as part of the records of the Committee any such complaints or concerns received pursuant to the Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing for a period of no less than seven years from the date on which the complaint was submitted, except that complaints and documents pertaining to complaints will be purged/destroyed sooner, to any extent and within any time frame mandated by applicable law.

3. The Committee shall annually review its own effectiveness and performance.

EXHIBIT D: MATERIAL CONTRACTS

The following are the material contracts of Fortis filed on SEDAR and EDGAR during 2016 or which were entered into prior to 2016 and are still in effect. Requests for additional copies of these material contracts should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). All such contracts are also available under the Corporation's profile at www.sedar.com and www.sec.gov.

Agreement and Plan of Merger

On February 9, 2016, Fortis entered into an Agreement and Plan of Merger with FortisUS, Element Acquisition Sub Inc., and ITC Holdings containing the terms and conditions upon which Fortis acquired ITC Holdings on October 14, 2016. A detailed summary of the Agreement and Plan of Merger was included in the Corporation's Management Information Circular dated March 18, 2016 starting on page 24, and such description is incorporated by reference herein.

Revolving Credit Facility

Fortis is a party to a Second Amended and Restated Credit Facility dated August 9, 2011, with The Bank of Nova Scotia as underwriter, sole lead arranger and bookrunner and administrative agent and Canadian Imperial Bank of Commerce and Royal Bank of Canada as co-syndication agents, and the lenders party thereto from time to time, as amended by the First Amending Agreement dated July 5, 2012, the Second Amending Agreement dated August 1, 2013, the Third Amending Agreement made as of March 23, 2015, the Fourth Amending Agreement made as of April 25, 2016, the Fifth Amending Agreement made as of August 17, 2016 and the Sixth Amending Agreement made as of October 5, 2016, each between Fortis, The Bank of Nova Scotia and the lenders named therein. The Fortis Second Amended and Restated Credit Facility is a $1.3 billion unsecured revolving credit facility and contains the terms and conditions upon which such credit is available to Fortis during the duration of the facility. The Second Amended and Restated Credit Facility contains customary representations and warranties, affirmative and negative covenants and events of default. Customary fees are payable by Fortis in respect of the facility and amounts outstanding under the facility bear interest at market rates.

Subscription Agreement

On April 20, 2016, Fortis, together with Finn Investment Pte Ltd (an affiliate of GIC), FortisUS, ITC Investment Holdings and Element Acquisition Sub Inc. entered into a Subscription Agreement pursuant to which an affiliate of GIC acquired 19.9% of ITC Holdings in connection with the acquisition thereof by Fortis on October 14, 2016. Pursuant to the Subscription Agreement, Finn Investment Pte Ltd agreed to purchase common stock of ITC Investment Holdings, the holder of all of the shares of ITC Holdings, for an aggregate cash purchase price of approximately US$1.0 billion, and notes of ITC Investment Holdings for an aggregate cash purchase price of approximately US$0.2 billion, in each case immediately prior to the effective time of the acquisition.

Shareholders' Agreement

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

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

Exchange and Registration Rights Agreement

The Exchange and Registration Rights Agreement between Fortis and Goldman Sachs & Co. dated October 4, 2016 sets forth the terms and conditions of exchange of the Corporation's outstanding US$500 million aggregate principal amount of 2.100% Notes due 2021 and US$1.5 billion aggregate principal amount of 3.055% Notes due 2026 (the "notes"). In the Registration Rights Agreement, Fortis agreed to use commercially reasonable efforts to: (1) no earlier than the last to occur of (i) the day after the closing date of the ITC acquisition; (ii) the filing of the Corporation's management information circular for the 2017 annual general meeting of shareholders and (iii) four months and one day after the day after the issuance of the notes and no later than 270 days after the closing date of the ITC acquisition, file with the SEC a registration statement on an appropriate registration form with respect to a registered offer to exchange the notes for new notes, with terms substantially identical in all material respects to the notes (except that such exchange notes will not contain terms with respect to transfer restrictions, the special mandatory redemption or any increase in annual interest rate, or with respect to rights relating to the exchange offer itself) and (2) cause the registration statement to become or be declared effective under the US Securities Act no later than 365 days after the closing date of the ITC acquisition.

When the exchange offer registration statement becomes effective or is declared effective by the SEC, Fortis will use commercially reasonable efforts to promptly commence an offering of the notes in return for Registrable Securities (as defined in the Registration Rights Agreement). The exchange offer will remain open for at least 20 business days. For each note surrendered under the exchange offer, the holders thereof will receive an exchange note of equal principal amount.

Fortis will pay additional interest on the notes if one of the following registration defaults occurs: (1) Fortis has not filed an exchange registration statement or shelf registration statement on or before the date on which such registration statement is required to be filed pursuant to the terms of the Registration Rights Agreement, (2) the exchange registration statement or shelf registration statement has not become effective or been declared effective by the SEC on or before the date on which such registration statement is required to become or be declared effective pursuant to the terms of the Registration Rights Agreement, (3) the exchange offer has not been completed within 30 business days following the effective date of the exchange registration statement, or (4) the exchange registration statement or shelf registration statement required by the terms of the Registration Rights Agreement is filed and becomes or is declared effective but shall thereafter either be withdrawn by Fortis in certain circumstances or becomes subject to an effective stop order issued pursuant to Section 8(d) of the US Securities Act suspending the effectiveness of such registration statement.

If a registration default occurs then additional interest may accrue on the principal amount of the notes at a rate of 0.25% per annum for the first 90 days of such registration default period, and at a per annum rate of 0.50% thereafter. Any additional interest will cease to accrue when the registration default is cured. A registration default is cured with respect to the notes, and additional interest ceases to accrue on such notes, when the exchange offer is completed or the registration statement becomes or is declared effective.

Indenture and First Supplemental Indenture

On October 4, 2016, Fortis entered in to an Indenture and a First Supplement Indenture thereto with The Bank of New York Mellon, as U.S. trustee, and BNY Trust Company of Canada, as Canadian co-trustee. The Indenture and the First Supplement Indenture set forth the terms of the Corporation's outstanding US$500 million aggregate principal amount of 2.100% Notes due 2021 and US$1.55 billion aggregate principal amount of 3.055% Notes due 2026. The Indenture contains customary covenants, events of default and rights for the benefit of securityholders and the trustees. An unlimited amount of debt securities may be issued under the Indenture, which is governed by the laws of the State of New York.