FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2015

February 17, 2016

ANNUAL INFORMATION FORM
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DEFINITIONS OF CERTAIN TERMS

Certain terms used in this 2015 Annual Information Form are defined below:

"2015 Annual Information Form" means this annual information form of the Corporation in respect of the year ended December 31, 2015;

"2015 Audited Consolidated Financial Statements" means the audited consolidated financial statements of the Corporation as at and for the years ended December 31, 2015 and 2014 and related notes thereto;

"ACC" means the Arizona Corporation Commission;

"Algoma Power" means Algoma Power Inc.;

"APS" means the Arizona Public Service Company;

"AUC" means the Alberta Utilities Commission;

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

"BCUC" means the British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

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

"BPC" means Brilliant Power Corporation;

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

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

"CEA" means the Canadian Electricity Association;

"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.;

"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;

"CPP" means the Clean Power Plan;

"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;

"EMS" means environmental management system;

"Entergy Nuclear Power" means Entergy Nuclear Power Marketing, LLC;

"EPA" means the United States Environmental Protection Agency;

"ERA" means the Electricity Regulatory Authority of the Cayman Islands;

"Ethos Energy" 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;

"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., but excludes its wholly owned partnership, Walden Power Partnership;

"FortisBC Energy" means FortisBC Energy Inc.;

"FortisOntario" means, collectively, the operations of Canadian Niagara Power, Cornwall Electric and Algoma Power;

"Fortis Properties" means Fortis Properties Corporation;

"FortisTCI" means FortisTCI Limited;

"Fortis Turks and Caicos" means, collectively, FortisTCI 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 Four Corners Generating Station;

"GHG" means greenhouse gas;

"GOB" means the Government of Belize;

"GSMIP" means Gas Supply Mitigation Incentive Plan;

"GWh" means gigawatt hour(s);

"IBEW" means the International Brotherhood of Electrical Workers;

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

"ISO" means International Organization for Standardization;

"ITC" means ITC Holdings Corp.;

"LNG" means liquefied natural gas;

“Management” means, collectively, the senior officers of the Corporation;

“Maritime Electric” means Maritime Electric Company, Limited;

“MATS” means Mercury and Air Toxics Standards;

“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, 2015;

“MGP” means manufactured gas plant;

“Moody’s” means Moody’s Investors Service, Inc.;

“MW” means megawatt(s);

“MWh” means megawatt hour(s);

“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.;

“NL PUB” means the Newfoundland and Labrador Board of Commissioners of Public Utilities;

“NYISO” means the New York Independent System Operator;

“OEB” means the Ontario Energy Board;

“OSM” means the United States Office of Surface Mining;

“PBR” means performance-based rate-setting;

“PCB” means polychlorinated biphenyl;

“PEI” means Prince Edward Island;

“PJ” means petajoule(s);

“PNM” means Public Service Company of New Mexico;

“PPA” means power purchase agreement;

“PPFAC” means purchased power and fuel adjustment clause;

“PRMP” means Price-Risk Management Plan;

“ROE” means rate of return on common shareholders’ equity;

“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;

“SJCC” means the San Juan Coal Company;

“Spectra Energy” means Westcoast Energy Inc. doing business as Spectra Energy Transmission;

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

"T&D" means transmission and distribution;

"TEP" means Tucson Electric Power Company;

"TJ" means terajoule(s);

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

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

"Walden" means the Walden Power Partnership;

"Waneta Expansion" means the 335-MW hydroelectric generating facility adjacent to the existing Waneta Plant on the Pend d'Oreille River in British Columbia;

"Waneta Partnership" means the Waneta Expansion Limited Partnership between CPC/CBT and Fortis;

"WECA" means the Waneta Expansion Capacity Agreement;

"WEG" means WildEarth Guardians; and

"Whistler" means the Resort Municipality of Whistler.

1.0 CORPORATE STRUCTURE

The 2015 Annual Information Form has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with US GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2015 Annual Information Form is given as of December 31, 2015.

Fortis includes forward-looking information in the 2015 Annual Information Form within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide Management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects Management's current beliefs and is based on information currently available to the Corporation's Management. The forward-looking information in the 2015 Annual Information Form, including the 2015 MD&A incorporated herein by reference, includes, but is not limited to, statements regarding: the acquisition of ITC, the expected timing and conditions precedent to the closing of the acquisition of ITC, including shareholder approvals of both ITC and Fortis, regulatory approvals, governmental approvals and other customary closing conditions; the expectation that Fortis will borrow funds to satisfy its obligation to pay the cash portion of the purchase price and will issue securities to pay the balance of the purchase price; the impact of the acquisition on the Corporation's earnings, mid-year rate base, credit rating, estimated enterprise value and compound annual growth rate; the expectation that the acquisition of ITC will be accretive in the first full year following closing and that the acquisition will support the average annual dividend growth target of Fortis; the expectation that the Corporation will become an SEC registrant and have its common shares listed on the New York Stock Exchange in connection with the acquisition; the expectation that Fortis will identify one or more minority investors to invest in ITC; forecast 2016 to 2020 midyear rate bases for the Corporation and its largest regulated utilities; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the Corporations consolidated forecast gross capital expenditures for 2016 and total capital spending over the five-year period from 2016 through 2020; the breakdown of total capital spending over the five-year period from 2016 through 2020; various natural gas investment opportunities that may be available to the Corporation; the nature, timing and expected costs of certain capital projects including, without limitation, the Tilbury liquefied natural gas facility expansions, the Residential Solar Program, the Lower Mainland System Upgrade Project, FortisAlberta's pole replacement program, the Gas Main Replacement Program at Central Hudson, Woodfibre pipeline expansion, New York Transco, LLC at Central Hudson, renewable energy alternatives at UNS Energy, Wataynikaneyap transmission line, the consolidations of Rural Electrification Associations and the construction of a diesel power plant at Caribbean Utilities; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; the expectation that the Corporation's subsidiaries will have reasonable access to long-term capital to fund their 2016 capital expenditure programs, operating and interest costs, and dividend payments; that TEP and UNS Electric expect to invest in renewable projects in 2016 to meet future renewable energy requirements; the impact of advances in technology and new energy efficiency standards on the Corporation's results of operations; the impact of new or revised environmental laws and regulations on the Corporation's results of operations; the expectation of the Corporation and its subsidiaries to remain compliant with existing, new or revised environmental laws and regulations; the expectation that there will be a significant reduction in the use of coal in certain of UNS Energy's generating facilities by 2022; and the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations.

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; FortisAlberta's continued recovery of its cost of service and ability to earn its allowed ROE under performance-based rate-setting, which commenced for a five-year term effective January 1, 2013; 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, electricity prices and fuel 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 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 and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; new or revised environmental laws and regulations will not severely affect the results of operations; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2018 or the adoption of International Financial Reporting Standards after 2018 that allows for the recognition of regulatory assets and liabilities; the continued tax deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably accurately assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in the MD&A for the year ended December 31, 2015 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2016 include, but are not limited to: uncertainty regarding the completion of the acquisition of ITC including but not limited to the receipt of shareholder approvals of ITC and Fortis, the receipt of regulatory and other governmental approvals, the availability of financing sources at the desired time or at all, on cost-efficient or commercially reasonable terms and the satisfaction or waiver of certain other conditions to closing; uncertainty related to the realization of some or all of the expected benefits of the acquisition of ITC; uncertainty regarding the outcome of regulatory proceedings of the Corporation's utilities, uncertainty of the impact *that 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; and risk associated with the impact of less favorable economic conditions on the Corporation's results of operations.*

All forward-looking information in the 2015 Annual Information Form 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 after the date hereof.

1.1 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 incorporation 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.

Fortis redeemed all of its outstanding First Preference Shares, Series A, First Preference Shares, Series B and First Preference Shares, Series C on September 30, 1997, December 2, 2002, and July 10, 2013, respectively. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004, 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G. On January 26, 2010, Fortis issued 10,000,000 First Preference Shares, Series H. On November 13, 2012, Fortis issued 8,000,000 First Preference Shares, Series J. On July 18, 2013, Fortis issued 10,000,000 First Preference Shares, Series K. On September 19, 2014, Fortis issued 24,000,000 First Preference Shares, Series M. On June 1, 2015, 2,975,154 First Preference Shares, Series H were converted into First Preference Shares, Series I, and 7,024,846 First Preference Shares, Series H remained outstanding.

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, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is a leader in the North American electric and gas utility business, with total assets of approximately $29 billion and fiscal 2015 revenue of $6.7 billion. The Corporation's asset mix is approximately 96% regulated utilities (70% electric, 26% gas), with the remaining 4% comprised of long-term contracted hydroelectric operations. The Corporation's regulated utilities serve more than 3 million customers across Canada and in the United States and the Caribbean. In 2015 the Corporation's electricity distribution systems met a combined peak demand of 9,705 MW and its gas distribution systems met a peak day demand of 1,323 TJ.

The Corporation's regulated holdings include electric distribution utilities in five Canadian provinces, two U.S. states and three Caribbean countries and natural gas utilities in the province of British Columbia and the states of Arizona and New York. As at December 31, 2015, approximately 47% of the Corporation's assets were located outside of Canada and approximately 49% of the Corporation's revenue was derived from foreign operations.

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 17, 2016. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10% of the Corporation's consolidated assets as at December 31, 2015, or the total revenue of which individually constituted less than 10% of the Corporation's 2015 consolidated revenue. The principal subsidiaries together comprise approximately 76% of the Corporation's consolidated assets as at December 31, 2015 and approximately 71% of the Corporation's 2015 consolidated revenue. FortisBC Electric and Newfoundland Power comprise approximately 7% and 5%, respectively, of the Corporation's consolidated assets as at December 31, 2015 and approximately 5% and 10%, respectively, of the Corporation's 2015 consolidated revenue.

Principal Subsidiaries		
Subsidiary	**Jurisdiction of Incorporation**	**Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation**
UNS Energy *(1)*	Arizona State, United States	100
Central Hudson *(2)*	New York State, United States	100
FortisBC Energy *(3)*	British Columbia, Canada	100
FortisAlberta *(4)*	Alberta, Canada	100

(1) UNS Energy, an Arizona State corporation, owns all of the shares of TEP, UNS Electric and UNS Gas. FortisUS, a Delaware State 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.

(2) CH Energy Group, a New York State corporation, owns all of the shares of Central Hudson. FortisUS, a Delaware State 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.

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

(4) 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.

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, Fortis has experienced significant growth in its business operations. Total assets have grown approximately 92% from $15.0 billion as at December 31, 2012 to $28.8 billion as at December 31, 2015. The Corporation's shareholders' equity has also grown approximately 93% from $5.4 billion as at December 31, 2012 to $10.4 billion as at December 31, 2015. Net earnings attributable to common equity shareholders have increased from $315 million in 2012 to $728 million in 2015.

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.

Over the past three years, Fortis has significantly increased its regulated utility investments through acquisitions. In June 2013 Fortis acquired CH Energy Group for a purchase price of approximately US$1.5 billion, including the assumption of US$518 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, 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. In August 2014 Fortis acquired UNS Energy for a purchase price of approximately US$4.5 billion, including the assumption of approximately US$2.0 billion of debt on closing. UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through its primary subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 663,000 electricity and gas customers.

On April 1, 2015, the Corporation completed construction of the $900 million, 335-MW Waneta Expansion hydroelectric generating facility ahead of schedule and on budget while maintaining an excellent safety and environmental protection record. Construction of the Waneta Expansion commenced late in 2010. Fortis has a 51% controlling ownership interest in the Waneta Expansion and operates and maintains the non-regulated investment. On April 2, 2015, the Waneta Expansion began generating power, all of which is being sold to BC Hydro and FortisBC Electric under 40-year contracts. In 2015, the Waneta Expansion contributed $22 million in earnings to the Corporation.

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 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 announced that it had reached terms of settlement with the GOB regarding the expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity.

In December 2015 the Corporation, through an indirect wholly owned subsidiary, entered into a definitive share purchase and sale agreement with Chevron Canada Properties Ltd. to acquire its share of the Aitken Creek Gas Storage Facility, the largest gas storage facility in British Columbia, with a total working gas capacity of 77 billion cubic feet for approximately US$266 million. The acquisition is subject to regulatory approval, and is expected to close in the first half of 2016.

The Corporation's gross consolidated capital expenditures for 2015 were approximately $2.2 billion, up approximately 30% from 2014. Over the past three years, including 2015, gross consolidated capital expenditures totalled $5.1 billion. Organic asset growth at the regulated utilities has been driven by the capital expenditure programs in western Canada. Total assets at FortisAlberta and the FortisBC gas and electric utilities have grown by approximately 27% and 9%, respectively, over the past three years. Organic growth at non-regulated operations has been driven by the construction of the Waneta Expansion.

2.2 Pending Acquisition of ITC

On February 9, 2016, Fortis and ITC entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction valued at approximately US$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. Under the terms of the transaction, ITC shareholders will receive US$22.57 in cash and 0.7520 Fortis common shares per ITC common share, representing total consideration of approximately US$6.9 billion, and Fortis will assume approximately US$4.4 billion of ITC consolidated indebtedness.

ITC is the largest independent pure-play electric transmission company in the United States. ITC owns and operates high-voltage transmission facilities in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, serving a combined peak load exceeding 26,000 MW along approximately 15,600 miles of transmission line. In addition, ITC is a public utility and independent transmission owner in Wisconsin.

ITC's tariff rates are regulated by FERC, which has been one of the most consistently supportive utility regulators in North America providing reasonable returns and equity ratios. Rates are set using a forward-looking rate-setting mechanism with an annual true-up, which provides timely cost recovery and reduces regulatory lag.

The closing of the acquisition is subject to ITC and Fortis shareholder approvals, the satisfaction of other customary closing conditions, and certain regulatory, state and federal approvals including, among others, those of FERC, the Committee on Foreign Investment in the United States, and the United States Federal Trade Commission/Department of Justice under the *Hart-Scott Rodino Antitrust Improvement Act*. The closing of the Acquisition is expected to occur in late 2016.

The pending acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix. On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the acquisition.

The financing of the acquisition has been structured to allow Fortis to maintain investment-grade credit ratings and is consistent with the Corporation's existing capital structure. Financing of the cash portion of the acquisition will be achieved primarily through the issuance of approximately US$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. In addition, Fortis has obtained commitments of US$2.0 billion from Goldman Sachs Bank USA to bridge the long-term debt financing and US$1.7 billion from The Bank of Nova Scotia to primarily bridge the sale of the minority investment in ITC. These non-revolving term credit facilities are repayable in full on the first anniversary of their advance, although syndication is not required, Fortis expects that these bridge facilities will be syndicated.

Upon completion of the acquisition, ITC will become a subsidiary of Fortis and approximately 27% of the common shares of Fortis will be held by ITC shareholders. In connection with the acquisition, Fortis will become a registrant with the SEC and will apply to list its common shares on the New York Stock Exchange and will continue to have its shares listed on the TSX.

2.3 Outlook

Fortis is focused on closing the acquisition of ITC by the end of 2016. The acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix.

Substantially all of Fortis' assets are low-risk, regulated utilities and long-term contracted energy infrastructure. No single regulatory jurisdiction comprises more than one third of total assets. Over the five-year period through 2020, excluding the acquisition of ITC, the Corporation's highly executable capital program is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to almost $21 billion in 2020 and produce a five-year compound annual growth rate in rate base of approximately 5%.

On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the acquisition of ITC. Following the acquisition, Fortis will be one of the top 15 North American public utilities ranked by enterprise value, with an estimated enterprise value of $42 billion. Additionally, ITC's midyear rate base, including construction work in progress, is expected to increase at a compound annual growth rate of approximately 7.5% through 2018, based on ITC's planned capital expenditure program.

Fortis continues to target 6% average annual dividend growth through 2020. 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 plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance.

Fortis expects long-term sustainable growth in rate base, assets and earnings resulting from strategic acquisitions and investment in its existing utility operations. The Corporation is also committed to identifying and executing on opportunities for incremental rate base and earnings growth through additional investments in existing service territories and in new franchise areas.

The approximate breakdown of the capital spending expected to be incurred over the five-year period from 2016 to 2020, excluding the acquisition of ITC, is as follows: 40% at Regulated Gas & Electric Utilities in the United States; 37% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 17% at Canadian Regulated Gas Utilities; 5% at Caribbean Regulated Electric Utilities; and the remaining 1% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 35% to meet customer growth; 50% to ensure continued and enhanced performance, reliability and safety of generation and T&D assets (i.e. sustaining capital expenditures); and 15% for facilities, equipment, vehicles, information technology and other assets.

Gross consolidated capital expenditures for 2016 are expected to be approximately $1.9 billion, as summarized in the following table. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast.

Forecast Gross Consolidated Capital Expenditures *(1)* **Year Ending December 31, 2016**	
	($ millions)
UNS Energy *(2)*	485
Central Hudson *(2)*	228
FortisBC Energy	349
FortisAlberta	441
FortisBC Electric	79
Eastern Canadian Electric Utilities	174
Regulated Electric Utilities – Caribbean *(2)*	127
Non-Regulated - Fortis Generation	15
Non-Regulated - Non-Utility *(3)*	3
Total	**1,901**

(1) *Relates to forecast cash payments to acquire or construct utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of allowance for funds used during construction.*

(2) *Forecast capital expenditures are based on a forecast exchange rate of US$1.00 = CAD$1.38.*

(3) *Includes forecast capital expenditures of approximately $3 million at FortisBC Alternative Energy Services Inc., which is reported in the Corporate and Other segment of the Corporation's 2015 Audited Consolidated Financial Statements.*

The most significant capital projects forecast for 2016 include:

- the Residential Solar Program at UNS Energy, consisting of the installation of rooftop solar systems for residential customers, for US$82 million, with forecast expenditures of US$16 million expected in 2016;
- the Gas Main Replacement Program at Central Hudson, a 15-year replacement program to eliminate and replace leakage-prone pipes throughout the gas distribution system with forecast expenditures of US$21 million expected in 2016 and US$98 million from 2017 through 2020 with the majority of spending expected post-2020;
- the ongoing Tilbury LNG facility expansion by FortisBC Energy, which includes the construction of a second LNG tank and a new liquefier, both to be in service by the end of 2016 at a total project cost of approximately $440 million with $326 million of project costs incurred to the end of 2015 and forecast expenditures of $105 million in 2016;
- the Lower Mainland System Upgrade project at FortisBC Energy, which is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia, to be completed in 2018 for an estimated project cost of $427 million with forecast expenditures of $50 million expected in 2016;
- the replacement of vintage poles under FortisAlberta's Pole-Management Program is expected to cost $336 million through 2020 with forecast expenditures of $42 million expected in 2016; and

- the purchase and turnkey installation of two 18.5 MW diesel-generating units, one 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment at Caribbean Utilities. The project cost is estimated to be US$85 million, with approximately US$48 million spent in 2015 and US$25 million forecast to be spent in 2016. The plant is expected to be commissioned in mid-2016.

FortisBC Energy is also pursuing additional LNG investment opportunities including a $600 million pipeline expansion for the proposed Woodfibre LNG site in British Columbia and further expansion of the Tilbury site that would include additional liquefaction, which investment opportunities are not included in the current capital expenditures forecast set forth in the table above.

Other potential projects that have not yet been included in the Corporation's capital expenditure forecast include, but are not limited to, the New York Transco, LLC at Central Hudson to address transmission constraints in New York; renewable energy alternatives at UNS Energy; Wataynikaneyap transmission line to connect remote First Nations communities at FortisOntario; further gas infrastructure opportunities at FortisBC Energy; and consolidation of Rural Electrification Associations at FortisAlberta.

The Corporation's subsidiaries expect to have reasonable access to long-term capital in 2016 to fund their capital expenditure programs.

Actual 2015 and forecast 2016 midyear rate base for the Corporation's reporting utility segments, as well as the Waneta Expansion, is provided in the following table.

Midyear Rate Base
($billions)

	Actual 2015	**Forecast 2016**
UNS Energy *(1)*	4.1	4.8
Central Hudson *(1)*	1.4	1.6
FortisBC Energy	3.7	3.7
FortisAlberta	2.7	3.0
FortisBC Electric	1.3	1.3
Eastern Canadian Electric Utilities	1.6	1.7
Regulated Electric Utilities – Caribbean *(1)*	0.8	0.9
Waneta Expansion	0.8	0.8
Total	**16.4**	**17.8**

(1) *Actual midyear rate base for 2015 is based on the actual average exchange rate of US$1.00=CAD$1.28 and forecast midyear rate base for 2016 is based on a forecast exchange rate of US$1.00=CAD$1.38.*

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an 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 generation assets, 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 business segments of the Corporation are: (i) Regulated Electric & Gas Utilities – United States; (ii) Regulated Gas Utility – Canadian; (iii) Regulated Electric Utilities – Canadian; (iv) Regulated Electric Utilities – Caribbean; (v) Non-Regulated – Fortis Generation; (vi) Non-regulated – Non-Utility; and (vii) Corporate and Other.

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

3.1 Regulated Electric & Gas Utilities - United States

3.1.1 *UNS Energy*

UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through its primary subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 663,000 electricity and gas customers. UNS Energy was acquired by Fortis in August 2014.

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 417,000 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 1,000,000 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 94,000 retail customers in Arizona's Mohave and Santa Cruz counties, which have a combined population of approximately 250,000.

TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,799 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, should satisfy the requirements of its customer base and meet future peak demand requirements. As at December 31, 2015, approximately 43% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility that serves approximately 152,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties, which have a combined population of approximately 700,000.

Market and Sales

UNS Energy's electricity sales were 15,366 GWh for 2015, compared to 14,560 GWh for the full year in 2014. 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 2015, comparable with the full year in 2014. Revenue was US$1,588 million for 2015, compared to US$1,560 million for the full year in 2014.

The following table provides the composition of UNS Energy's 2015 and 2014 revenue, electricity sales, and gas volumes by customer class.

UNS Energy *(1)*
Revenue and Electricity & Gas Sales by Customer Class

	Revenue (%)		GWh Sales (%)		PJ Volumes (%)	
	2015	2014	**2015**	2014	**2015**	2014
Residential	**37.3**	36.2	**29.8**	31.2	**55.1**	53.8
Commercial	**22.5**	22.5	**17.7**	19.1	**23.7**	24.1
Industrial	**17.0**	16.9	**21.8**	23.9	**2.0**	2.1
Other (2)	**23.2**	24.4	**30.7**	25.8	**19.2**	20.0
Total	**100.0**	100.0	**100.0**	100.0	**100.0**	100.0

(1) *The 2014 information presented is for the year ended December 31, 2014. UNS Energy was acquired by Fortis in August 2014; therefore, only financial results from the date of acquisition, August 15, 2014, are reflected in the comparatives of the Corporation's 2014 Audited Consolidated Financial Statements.*

(2) *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 2,501 MW and its transmission and distribution system consisting of approximately 15,654 kilometres of line. In 2015, TEP met a peak demand of 2,860 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.

At December 31, 2015, TEP owned 2,501 MW of generating capacity, as 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	Springerville, AZ	1985	Coal	387	TEP	49.5	192
Springerville Station	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 *(1)*	3	Gila Bend, AZ	2003	Gas	550	Ethos Energy	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/Oil	104	TEP	100.0	104
Sundt Station *(2)*	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		Ft. Huachuca, AZ	2014	Solar	17	TEP	100.0	17
Total Capacity *(3)*								**2,501**

(1) *In December 2014, TEP and UNS Electric together completed the acquisition of Unit 3 of the Gila River Power Station, a 550 MW gas-fired combined-cycle unit for US$219 million. Both TEP and UNS Electric rely on a portfolio of long-term, medium-term and short-term PPAs to meet customer load requirements.*

(2) *In August 2015, TEP exhausted its existing coal supply at Sundt Station and has been operating Sundt Station with natural gas as a primary fuel source. TEP expects to retire the Sundt Station earlier than expected, and has requested to apply excess depreciation reserves against the unrecovered net book value in its 2015 rate case.*

(3) *Excludes 913 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 73% of its 407 MW 2015 peak capacity needs.

UNS Electric's generating capacity as of December 31, 2015 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 Energy	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 (175 MW), wind resources (80 MW) and a landfill gas generation plant (4 MW). UNS Electric satisfies its respective requirements through its 8 MW of owned photovoltaic solar generating capacity and PPAs for capacity from solar resources (10 MW) and wind resources (10 MW). TEP and UNS Electric expect to spend US$64 million on renewable projects in 2016 to meet future renewable energy requirements which are recoverable through rates.

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.

Legal Proceedings

Springerville Generating Station, Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint against TEP with FERC, alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning in January 2015 for the price specified by the third-party owners. In February 2015 FERC issued an order denying the third-party owners' complaint. In March 2015 the third-party owners filed a request for rehearing in the FERC action, which FERC denied in October 2015. In December 2015 the third-party owners appealed FERC's order denying the third party-owners' complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015 TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

In December 2014 the third-party owners filed a complaint against TEP in the Supreme Court of the State of New York, New York County. In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged and the court's subsequent ruling on the motions, the third-party owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York action and in the arbitration proceeding described below. As amended, the New York action alleges, among other things, that TEP failed to properly operate, maintain, and make capital investments in Springerville Unit 1 during the term of the leases; and that TEP breached the lease transaction documents by refusing to pay certain of the third-party owners' claimed expenses. The third amended complaint seeks US$71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The third-party owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC action. In November 2015 the third-party owners filed a motion for summary judgment on their claim that TEP failed to pay certain of the third-party owners' claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent notices to TEP that alleged that TEP had defaulted under the third-party owners' leases. The notices demanded that TEP pay liquidated damages totalling approximately US$71 million. In letters to the owner trustees, TEP denied the allegations in the notices.

In April 2015 TEP filed a demand for arbitration with the American Arbitration Association seeking an award of the owner trustees and co-trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015 the third-party owners filed a separate demand for arbitration with the American Arbitration Association alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The third-party owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the third-party owners' fees and expenses. TEP and the third-party owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015 the third-party owners filed an amended arbitration demand adding claims that TEP has converted the third-party owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity.

In October 2015 the arbitration panel granted TEP's motion for interim relief, ordering the third-party trustees and co-trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the third-party owners' motion for interim relief, which had requested that TEP be enjoined from dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling the third-party owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 2015. The arbitration hearing is scheduled for July 2016.

In November 2015 TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming the owner trustee and co-trustee as respondents. The petition seeks an order from the court confirming the interim arbitration order under the Federal Arbitration Act. In December 2015 the owner trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As of December 31, 2015 TEP billed the third-party owners approximately US$23 million for their pro-rata share of Springerville Unit 1 expenses and US$4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the claims, TEP cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the 2015 Audited Consolidated Financial Statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners and to vigorously pursue the claims it has asserted against the third-party owners.

TEP and the third-party owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

Navajo Generating Station Lease Extension
Navajo Generating Station is located on a site that is leased from the Navajo Nation with an initial lease term through 2019. The Navajo Nation signed a lease amendment in 2013 that would extend the lease from 2019 through 2044. The participants in Navajo Generating Station, including TEP, have not signed the lease amendment because certain participants have expressed an interest in discontinuing their participation in Navajo Generating Station. Negotiations between the participants are ongoing, and all parties will likely agree to the terms. To become effective, this lease amendment must be signed by all of the participants, approved by the U.S. Department of the Interior, and is subject to environmental reviews. Once the lease amendment becomes effective, the participants will be responsible for additional lease costs from the date the Navajo Nation signed the lease amendment. TEP owns 7.5% of Navajo Generating Station. In 2015, TEP recorded additional estimated lease expense of approximately US$1 million with the expectation that the lease amendment will become effective. As at December 31, 2015 a total liability of US$3 million (December 31, 2014 – US$2 million) was recognized.

Environmental Contingencies

San Juan Generating Station
In August 2013, the U.S. Bureau of Land Management proposed regulations that, among other things, redefine the term "underground mine" to exclude high-wall mining operations and impose a higher surface mine coal royalty on high-wall mining. SJCC utilized high-wall mining techniques at its surface mines prior to beginning underground mining operations in January 2003. If the proposed regulations become effective, SJCC may be subject to additional royalties on coal delivered to San Juan between August 2000 and January 2003 totaling approximately US$5 million of which TEP's proportionate share would approximate US$1 million. TEP owns 50% of Units 1 and 2 at San Juan, which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. TEP cannot predict the final outcome of the Bureau of Land Management's proposed regulations.

In February 2013 WEG filed a Petition for Review in the U.S. District Court 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 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 OSM administrative actions in 2008. WEG alleges various NEPA violations against OSM, including, but not limited to, 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 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 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. The parties have requested the court to stay this matter until April 2016 in furtherance of settlement negotiations. If WEG ultimately obtains the relief it has requested, such a ruling could require significant expenditures to reconfigure operations at the San Juan mine, impact the production of coal, and impact the economic viability of the San Juan mine and San Juan. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Four Corners Generating Station
In October 2011 EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the U.S. District Court for the District of New Mexico against APS and the other Four Corners Generating Station participants alleging violations of the prevention of significant deterioration provisions of the Clean Air Act at Four Corners Generating Station. In January 2012 EarthJustice amended their complaint alleging violations of New Source Performance Standards resulting from equipment replacements at Four Corners Generating Station. Among other things, the plaintiffs sought to have the court issue an order to cease operations at Four Corners Generating Station until any required prevention of significant deterioration permits are issued and order the payment of civil penalties, including a beneficial mitigation project. In April 2012, APS filed motions to dismiss with the court for all claims asserted by EarthJustice in the amended complaint.

TEP owns 7% of Four Corners Generating Station Units 4 and 5 and is liable for its share of any resulting liabilities. In June 2015 APS, the operator of Four Corners Generating Station, announced a settlement with the EPA for outstanding environmental issues related to New Source Review provisions under the Clean Air Act. The settlement calls for environmental upgrades including selective catalytic reduction upgrades already planned for under the Regional Haze regulation, environmental mitigation projects, and civil penalties. A consent decree reflecting terms of the settlement was entered by the court in August 2015, effectively closing the case. TEP's share of the additional capital, excluding the selective catalytic reduction upgrades, is approximately US$2 million over the three year period it will take to construct the upgrades. TEP's share of the annual operations and maintenance expenses is approximately US$1 million. In addition, TEP recorded less than US$1 million for its share of the one-time charges for environmental mitigation projects and civil penalties.

In May 2013 the New Mexico Taxation and Revenue Department issued a notice of assessment for coal severance tax, penalties, and interest totaling US$30 million to the coal supplier at Four Corners. TEP's share of the assessment is US$1 million based on its ownership percentage. In December 2013, the coal supplier and Four Corners Generating Station's operating agent filed a claim contesting the validity of the assessment on behalf of the participants in Four Corners Generating Station, who will be liable for their share of any resulting liabilities. In June 2015 the U.S. District Court ruled in favor of the Four Corners Generating Station's participants. The New Mexico Taxation and Revenue Department filed an appeal of the decision in August 2015. TEP cannot predict the final outcome or timing of resolution of these claims.

Mine Reclamation Costs
TEP pays ongoing reclamation costs related to coal mines that supply generating stations 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$43 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The mine reclamation liability recorded as at December 31, 2015 was US$25 million (December 31, 2014 – US$22 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.

Human Resources

As at December 31, 2015: (i) TEP employed approximately 1,478 employees, of whom 688 are represented by IBEW under a collective agreement expiring in January 2019; (ii) UNS Electric employed 145 approximately employees, of whom 111 are represented by IBEW under collective agreements expiring in June 2016 and February 2017; and (iii) UNS Gas employed approximately 184 employees, of whom 111 are represented by IBEW under collective agreements expiring February 2017 and June 2018. UniSource Energy Services Inc., another wholly owned subsidiary of UNS Energy, employed approximately 208 employees, of whom 199 are represented by IBEW under collective agreements expiring in May 2016, July 2016 and December 2016.

3.1.2 *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 was acquired by Fortis as part of the acquisition of CH Energy Group in June 2013.

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. Central Hudson's 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 1,059 MW in 2015.

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 2015 Central Hudson's natural gas system met a peak day demand of 140 TJ.

Market and Sales

Central Hudson's electricity sales were 5,132 GWh for 2015, compared to 5,075 GWh for 2014. Natural gas sales volumes for 2015 were 24 PJ, compared to 23 PJ for 2014. Revenue was US$691 million for 2015, compared to US$743 million in 2014.

The following tables compare the composition of Central Hudson's 2015 and 2014 revenue, electricity sales and gas volumes by customer class.

Central Hudson Revenue and Electricity Sales by Customer Class				
	Revenue (%)		GWh Sales (%)	
	2015	2014	**2015**	2014
Residential	**61.0**	60.9	**40.6**	40.3
Commercial	**26.4**	28.0	**38.0**	37.8
Industrial	**4.0**	4.1	**19.7**	20.1
Other	**7.9**	6.2	**0.7**	0.7
Sales for Resale	**0.7**	0.8	**1.0**	1.1
Total	**100.0**	100.0	**100.0**	100.0

Central Hudson Revenue and Gas Volumes by Customer Class				
	Revenue (%)		PJ Volumes (%)	
	2015	2014	**2015**	2014
Residential	**52.9**	53.5	**26.1**	27.1
Commercial	**26.5**	29.0	**33.1**	33.9
Industrial	**8.3**	4.8	**20.2**	17.2
Other	**3.1**	1.1	**7.7**	7.8
Sales for Resale	**9.2**	11.6	**12.9**	14.0
Total	**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 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.

In June 2014 Central Hudson entered into a PPA to purchase capacity from the Danskammer Generating Facility from October 2014 through August 2018, with approximately US$76 million in purchase commitments remaining as at December 31, 2015.

In November 2013 Central Hudson entered into a PPA to purchase 200 MW of installed capacity from the Roseton Generating Facility from May 2014 through April 2017, with approximately US$14 million in purchase commitments remaining as at December 31, 2015.

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.

Other Contractual Obligations

CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of, and return on, five high-voltage transmission projects totaling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of its maximum commitment. As at December 31, 2015, no payment obligation was expected under this guarantee.

Litigation

Asbestos Litigation
Prior to and after its acquisition by Fortis, various asbestos lawsuits had been brought against Central Hudson. While a total of 3,350 asbestos cases have been raised, 1,167 remained pending as at December 31, 2015. Of the cases no longer pending against Central Hudson, 2,027 have been dismissed or discontinued without payment by Central Hudson, and it has settled the remaining 156 cases. The company is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in 2015 Audited Consolidated Financial Statements.

Environmental Contingencies

Former MGP Facilities
Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid to late 1800s with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The New York State Department of Environmental Conservation, which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The New York State Department of Environmental Conservation has further requested that the company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2015, an obligation of US$92 million (December 31, 2014 – US$105 million) was recognized in respect of MGP remediation and, based upon cost model analysis completed in 2014, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the New York State Public Service Commission, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return.

Human Resources

As at December 31, 2015, Central Hudson employed approximately 966 employees, of whom 566 are represented by IBEW under a collective agreement expiring April 30, 2017.

3.2 Regulated Gas Utility - Canadian

3.2.1 FortisBC Energy

FortisBC Energy is the largest distributor of natural gas in British Columbia, serving approximately 982,000 residential, commercial and industrial and transportation customers in more than 135 communities. Major areas served by FortisBC Energy include the Lower Mainland, Vancouver Island and Whistler regions of British Columbia.

In addition to providing T&D services to customers, FortisBC Energy also obtains natural gas supplies on behalf of most residential, commercial and industrial customers.

FortisBC Energy owns and operates approximately 48,000 kilometres of natural gas pipelines and met a peak day demand of 1,074 TJ in 2015.

Market and Sales

FortisBC Energy's natural gas sales volumes were 186 PJ in 2015, compared to 195 PJ in 2014. Revenue decreased from $1,435 million in 2014 to $1,295 million in 2015.

The following table compares the composition of FortisBC Energy's 2015 and 2014 revenue and natural gas volumes by customer class.

FortisBC Energy Revenue and Gas Volumes by Customer Class				
	Revenue (%)		PJ Volumes (%)	
	2015	2014	**2015**	2014
Residential	**56.8**	56.2	**36.0**	36.9
Commercial	**29.1**	30.2	**23.1**	23.1
Industrial	**1.7**	2.7	**1.6**	2.1
Transportation	**7.8**	6.8	**33.9**	31.8
Other (1)	**4.6**	4.1	**5.4**	6.1
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes amounts under fixed-revenue contracts and revenue from sources other than from the sale of natural gas.*

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. These counterparties adhere to standards of counterparty creditworthiness and contract execution and/or management policies. FortisBC Energy contracts for approximately 136 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 35.3 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 0.74 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 $1.0 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 year ended October 31, 2015.

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.

Price-Risk Management Plan

FortisBC Energy engages in price-risk management activities to mitigate the impact to 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. Prior to 2010, FEI also typically included the use of derivative instruments which were implemented pursuant to an annual price risk management plan reviewed and approved by the BCUC. Following a comprehensive review process, in July 2011 the BCUC directed FEI to suspend the majority of its natural gas commodity hedging activities. All hedges that had been in place from previously approved PRMPs prior to the suspension of the hedging strategy, expired in 2014.

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. FortisBC Energy is currently awaiting the BCUC's determination regarding the review process for this application.

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.

The program has been in place since November 2004 for commercial customers and November 2007 for residential customers. For the year ended December 31, 2015, approximately 4% of eligible commercial customers and 3% of eligible residential customers participated in the program by purchasing their commodity supply from alternate providers.

Legal Proceedings

In April 2013 FHI, the parent of FortisBC Energy, and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band. The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Coldwater Indian Band seeks orders cancelling the right of way and claims damages for wrongful interference with its use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Human Resources

As at December 31, 2015, FortisBC Energy had approximately 1,620 full-time equivalent employees. Approximately 70% of the employees are represented by IBEW and COPE under collective agreements. The IBEW collective agreement came into effect on April 1, 2015 and expires on March 31, 2019. There are two collective agreements between COPE and FortisBC Energy which expire March 31, 2017 and March 31, 2018, respectively.

3.3 Regulated Electric Utilities - Canadian

3.3.1 *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 121,000 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 539,000 customers, comprising residential, commercial, farm, oil and gas and industrial consumers, and met a peak demand of 2,733 MW in 2015.

Market and Sales

FortisAlberta’s annual energy deliveries decreased from 17,372 GWh in 2014 to 17,132 GWh in 2015. Revenue was $563 million in 2015 compared to $518 million in 2014.

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 2015 and 2014 revenue and energy deliveries by customer class.

FortisAlberta Revenue and Energy Deliveries by Customer Class				
	Revenue (%)		GWh Deliveries [(1)] (%)	
	2015	2014	**2015**	2014
Residential	**29.4**	30.5	**17.5**	17.1
Large commercial, industrial and oil field	**21.9**	21.5	**60.7**	61.3
Farms	**13.5**	11.8	**7.9**	7.5
Small commercial	**12.0**	10.8	**8.0**	8.0
Small oil field	**9.6**	8.1	**5.5**	5.7
Other [(2)]	**13.6**	17.3	**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 6,663 GWh in 2015 and 7,076 GWh in 2014, based on interim settlement that is expected to be finalized in May 2016, 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 that related to 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 156 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 a further five years. 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.

Human Resources

As at December 31, 2015, FortisAlberta had approximately 1,162 full-time equivalent employees. Approximately 80% of the employees of FortisAlberta are members of the UUWA and represented by a collective agreement that expires on December 31, 2017.

3.3.2 *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 a diverse mix of approximately 168,000 customers, of whom approximately 132,000 are served directly by FortisBC Electric in Kelowna, Oliver, Osoyoos, Trail, Castlegar, Creston and Rossland, while the remainder are served through the wholesale supply of power to municipal distributors in the communities of Summerland, Penticton, Grand Forks and Nelson, as well as to BC Hydro. In 2015, FortisBC Electric met a peak demand of 624 MW. Residential customers represent the largest customer class of the company. FortisBC Electric's T&D assets include approximately 7,200 kilometres of T&D lines and 65 substations.

FortisBC Electric also includes the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro; the 335-MW Waneta Expansion, owned by Fortis and CPC/CBT; the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT; and the 185-MW Arrow Lakes hydroelectric plant 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 3,116 GWh in 2015, compared to 3,179 GWh in 2014. Revenue increased to $360 million in 2015 from $334 million in 2014.

The following table compares the composition of FortisBC Electric's 2015 and 2014 revenue and electricity sales by customer class.

FortisBC Electric Revenue and Electricity Sales by Customer Class				
	Revenue (%)		**GWh Sales (%)**	
	2015	2014	**2015**	2014
Residential	**45.3**	48.4	**40.2**	41.2
Commercial	**24.0**	24.7	**29.1**	28.9
Wholesale	**12.2**	13.0	**18.6**	18.1
Industrial	**8.3**	9.0	**12.1**	11.8
Other [(1)]	**10.2**	4.9	**-**	-
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 45% of the company's energy needs and 30% of its peak capacity needs. FortisBC Electric meets the balance of its requirements through a portfolio of long-term and short-term PPAs.

FortisBC Electric's four hydroelectric generating facilities are governed by the multi-party CPA that enables the 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 the following power purchase contracts:

i. a 149-MW long-term PPA with BPC terminating in 2056 (Brilliant PPA);
ii. a 200-MW PPA with BC Hydro terminating in 2033 (BC Hydro PPA);
iii. a capacity and energy purchase agreement with CPC, for a total of 78,500 MWh from 2013 through 2017 (Brilliant Expansion Capacity and Energy Purchase Agreement);
iv. a number of small power purchase contracts with independent power producers;
v. spot market and contracted capacity purchases; and
vi. a 40-year agreement to purchase 234 MW of capacity from the WECA.

These purchase contracts have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Electric's electricity rates.

Brilliant PPA
Under the Brilliant PPA, FortisBC Electric has agreed to purchase from BPC, on a long-term basis: (i) the entitlement allocated to the Brilliant hydroelectric plant; and (ii) after the expiration of the CPA, the actual electrical output generated by the Brilliant hydroelectric plant. While the total entitlement is 985,000 MWh, FortisBC Electric does not purchase the approximate 60,000 MWh of regulated flow upgrade entitlement under the Brilliant PPA. However, FortisBC Electric has entered into another agreement with CPC for this energy over a five-year period, as discussed below. The Brilliant PPA uses a take-or-pay contract structure, which requires that FortisBC Electric pay for the Brilliant hydroelectric plant's entitlement, irrespective of whether FortisBC Electric actually takes it. FortisBC Electric does not foresee any circumstances under which FortisBC Electric would be required to pay for power that it does not require. During the first 30 years of the Brilliant PPA term, FortisBC Electric pays to BPC an amount that covers the operation and maintenance costs of the Brilliant hydroelectric plant and provides a return on capital, including original purchase costs, sustaining capital costs and any life-extension investments. During the second 30 years of the Brilliant PPA term, commencing in 2026, an adjustment using a market-price mechanism based on the depreciated value of the Brilliant hydroelectric plant and then-prevailing operating costs will be made to the amounts payable by FortisBC Electric. The Brilliant PPA provided FortisBC Electric with approximately 27% of its energy requirements in 2015.

BC Hydro PPA
FortisBC Electric is a party to the BC Hydro PPA, which provides FortisBC Electric with additional electricity for purposes of supplying its load requirements, up to a maximum demand of 200 MW. Energy bought pursuant to the BC Hydro PPA provided approximately 15% of FortisBC Electric's energy requirements in 2015. The current BC Hydro PPA was approved by the BCUC in May 2014 and expires in September 2033.

Brilliant Expansion Capacity and Energy Purchase Agreement
In November 2012, FortisBC Electric entered into an agreement to purchase CPC's unused capacity and energy entitlements from 2013 to 2017. The entitlements are from the Brilliant hydroelectric plant and the Brilliant hydroelectric expansion plant, including the 60,000 MWh from the Brilliant hydroelectric plant that is not included in the Brilliant PPA. The agreement is for a total of 78,500 MWh and provided approximately 2% of FortisBC Electric's energy requirements in 2015.

Small Power Purchase Contracts
FortisBC Electric has a number of small power purchase contracts with independent power producers, which collectively provided less than 1% of FortisBC Electric's energy supply requirements in 2015. The majority of these contracts have been accepted by the BCUC.

Spot Market and Contracted Capacity Purchases
During 2014, FortisBC Electric purchased capacity and energy from the market to meet its peak energy requirements and optimize its overall power supply portfolio. To facilitate market transactions going forward, FortisBC Electric entered into the CEPSA with Powerex Corp. which was approved by the BCUC in April 2015. The CEPSA is a master agreement that sets the terms and conditions for future market transactions entered into by FortisBC Electric with Powerex Corp. The CEPSA became effective May 1, 2015 and expires on September 30, 2018, unless extended by a mutual agreement. Spot market and contracted purchases provided approximately 8% of FortisBC Electric's energy supply requirements in 2015.

WECA
The Corporation entered into the WECA to purchase capacity from the Waneta Expansion. The Waneta Expansion is owned and operated by a limited partnership, the limited partners of which are Fortis, which owns a 51% interest, and a wholly owned subsidiary of each of CPC/CBT. The WECA, which was approved by the BCUC in May 2012, allows FortisBC Electric to purchase capacity over a 40 year period as of April 2, 2015.

Legal Proceedings

The Government of British Columbia filed a claim in the B.C. Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has notified its insurers, it has been advised by the Government of British Columbia that a response to the claim is not required at this time. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2015 Audited Consolidated Financial Statements.

Human Resources

As at December 31, 2015, FortisBC Electric had approximately 507 full-time equivalent employees. Approximately 70% of the employees are represented by IBEW and COPE. The IBEW collective agreement expires January 31, 2018. FortisBC Electric's two COPE collective agreements expire March 31, 2017 and December 31, 2018.

3.3.3 *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 262,000 customers in approximately 600 communities. Newfoundland Power has installed generating capacity of 139 MW and met a peak demand of 1,359 MW in 2015. Newfoundland Power owns and operates approximately 12,000 kilometres of T&D lines.

The Corporation, through FortisWest, holds all of the common shares of Maritime Electric, an integrated electric utility and the principal distributor of electricity on PEI, serving approximately 78,000 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 on-Island generating plants with a combined capacity of 150 MW on PEI and met a peak demand of 264 MW in 2015. Maritime Electric owns and operates approximately 5,800 kilometres of T&D lines.

FortisOntario provides integrated electric utility service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are comprised of Canadian Niagara Power, Cornwall Electric and Algoma Power. FortisOntario also owns a 10% interest in certain regional electric distribution companies serving approximately 40,000 customers. FortisOntario met a combined peak demand of 260 MW in 2015. FortisOntario owns and operates approximately 3,600 kilometres of T&D lines.

Market and Sales

Electricity sales attributable to the Eastern Canadian Electric Utilities were 8,403 GWh in 2015 compared to 8,376 GWh in 2014. Revenue was $1,033 million in 2015 compared to $1,008 million in 2014.

The following table compares the composition of revenue and electricity sales by customer class at Eastern Canadian Electric Utilities in 2015 and 2014.

Eastern Canadian Electric Utilities
Revenue and Electricity Sales by Customer Class

	Revenue (%)		**GWh Sales (%)**	
	2015	2014	**2015**	2014
Residential	**56.6**	56.1	**56.9**	56.4
Commercial and Industrial	**40.1**	41.1	**43.0**	43.5
Other [(1)]	**3.3**	2.8	**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 NL PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

The purchased power rate structure is the basis upon which 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 general rate application before the NL PUB which will establish a new wholesale rate for Newfoundland Power. The outcome of this application, and future changes in supply costs, including costs associated with Nalcor Energy's Muskrat Falls hydroelectric generation development and associated transmission assets, may affect electricity prices in a manner that affects Newfoundland Power's sales. The recovery of Muskrat Falls development costs are expected to materially increase customer electricity rates.

Newfoundland Power experienced losses of electricity supply from Newfoundland Hydro in January 2013 and January 2014, which disabled Newfoundland Power from meeting all of its customers' requirements. The NL PUB is conducting an inquiry and hearing into these system supply issues and power interruptions. To the extent it is able, Newfoundland Power intends to participate in these reviews in 2016. The NL PUB's final report on the adequacy and reliability of the Island Interconnected system until interconnection with Muskrat Falls is currently outstanding. A consideration of longer term issues associated with adequacy and reliability on the Island Interconnected system after interconnection with Muskrat Falls is ongoing. The Government of Newfoundland and Labrador has engaged consultants to complete an independent review of the electricity system in Newfoundland and Labrador. The consultant's report, released on October 30, 2015, indicated that Newfoundland Power's operations were substantially in compliance with industry best practice and that the NL PUB's oversight of the company appears to provide regulatory predictability and certainty.

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. The diesel plants and gas turbines have a total capacity of approximately 5 MW and 37 MW, respectively.

Maritime Electric
Maritime Electric purchased 75% of the electricity required to meet its customers' needs from NB Power in 2015. 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 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, through the Hydroelectric Contract Initiative, from the five hydroelectric generating plants of the 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 contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per year. Both contracts expire in December 2019.

Human Resources

Newfoundland Power
As at December 31, 2015, Newfoundland Power had approximately 653 full-time equivalent employees, and approximately 49% of its employees were represented by IBEW under two collective agreements expiring September 30, 2017. One bargaining unit is composed predominately of clerical employees and the other predominately of skilled trade workers.

Maritime Electric
As at December 31, 2015, Maritime Electric had approximately 182 full-time equivalent employees, of whom approximately 70% were represented by IBEW under a collective agreement expiring December 31, 2018.

FortisOntario
As at December 31, 2015, FortisOntario had approximately 198 full-time equivalent employees, of whom approximately 58% were represented by CUPE, in Cornwall; IBEW in the Niagara region and Gananoque; and Power Workers Union, a CUPE affiliate, in the Algoma region. The expiry dates of the collective agreements are April 30, 2016; February 29, 2016 and July 31, 2016; and December 31, 2016, respectively.

3.4 Regulated Electric Utilities - Caribbean

The 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, serving approximately 28,000 customers. The company met a peak demand of 101 MW in 2015. Caribbean Utilities owns and operates more than 700 kilometres of T&D lines, including 24 kilometres of submarine cable. Fortis holds an approximate 60% (December 31, 2014 – 60%) controlling ownership interest in the utility. Caribbean Utilities is a public company traded on the TSX (TSX:CUP.U).

Fortis Turks and Caicos is comprised of two integrated electric utilities serving approximately 14,000 customers on certain islands in Turks and Caicos. The utilities met a combined peak demand of approximately 38 MW in 2015. Fortis Turks and Caicos owns and operates approximately 600 kilometres of T&D lines.

Market and Sales

Electricity sales of Regulated Electric Utilities – Caribbean were 802 GWh in 2015, compared to 771 GWh in 2014. Revenue was $321 million in both 2015 and 2014.

The following table compares the composition of revenue and electricity sales by customer class at the Regulated Electric Utilities – Caribbean for 2015 and 2014.

Regulated Electric Utilities – Caribbean *(1)*
Revenue and Electricity Sales by Customer Class

	Revenue (%)		**GWh Sales (%)**	
	2015	2014	**2015**	2014
Residential	**42.9**	44.0	**43.0**	42.6
Commercial and Industrial	**56.2**	54.9	**57.0**	57.4
Other *(2)*	**0.9**	1.1	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Excludes Belize Electricity.*
(2) *Includes revenue from sources other than from the sale of electricity.*

Power Supply

Caribbean Utilities relies upon in-house diesel-powered generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and it must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. Caribbean Utilities has an installed diesel-powered generating capacity of approximately 132 MW.

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. Each contract was renewed for an additional 18-month term in September 2014 and is under negotiation for renewal in March 2016. The approximate combined quantity under the contracts for 2016 is 20 million imperial gallons. These contracts enable Caribbean Utilities to purchase fuel from the suppliers on what it believes to be competitive terms and pricing. The fuel contracts include disaster recovery and business continuity plans in the event of foreseeable disruptions to fuel supplies to reduce the impact on Caribbean Utilities' operations.

In October 2014 the ERA announced that Caribbean Utilities was the successful bidder for new generation capacity. Caribbean Utilities will develop and operate a new 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 cost is estimated at US$85 million and the plant is expected to be commissioned mid-2016. Subsequently, in November 2014 the ERA issued a new non-exclusive Electricity Generation License to Caribbean Utilities for a term of 25 years, expiring in November 2039.

Fortis Turks and Caicos relies upon in-house diesel-powered generation, with an installed generating capacity of 82 MW, to produce electricity for its customers. In September 2015 the third Wartsila generating unit was placed into commercial production.

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 12 million imperial gallons per annum.

Human Resources

As at December 31, 2015, Regulated Electric Utilities - Caribbean employed approximately 356 full-time equivalent employees. The 201 employees at Caribbean Utilities and 155 employees at Fortis Turks and Caicos are non-unionized.

3.5 Non-Regulated - Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Non-Regulated - Fortis Generation Assets			
Location	**Plants**	**Fuel**	**Capacity (MW)**
Belize	3	hydro	51
British Columbia	2	hydro	351
Ontario	1	thermal	5
Total	**6**		**407**

The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary BECOL under a franchise agreement with the GOB. The non-regulated generation operations of BECOL consist of the 25-MW Mollejon, 7-MW Chalillo and 19-MW Vaca hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under 50-year PPAs expiring in 2055 and 2060.

The non-regulated generation operations of FortisBC Inc. include the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia. All of the output of the facility is sold to BC Hydro under a long-term contract that cannot be terminated prior to 2024. As at December 31, 2015, the Walden hydroelectric generating facility has been classified as held for sale.

Non-regulated generation operations in British Columbia also include the Corporation's 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. Construction of the $900 million, 335-MW Waneta Expansion was completed on April 1, 2015, ahead of schedule and on budget. Construction of the Waneta Expansion, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, commenced late in 2010. The expansion added a second powerhouse, immediately downstream of the Waneta Dam on the Pend d'Oreille River, that shares the existing hydraulic head and generates clean, renewable, cost-effective power from water that would otherwise be spilled. The project also included construction of a 10-kilometre, 230-kilovolt transmission line. On April 2, 2015, the Waneta Expansion began generating power, all of which is being sold to BC Hydro and FortisBC Electric under 40-year contracts. FortisBC Electric operates and maintains the non-regulated investment.

Non-regulated generation operations of FortisOntario are comprised of the operation of a 5-MW gas-powered cogeneration plant in Cornwall. All thermal energy output of this plant is sold to external third parties, while the electricity output is sold to Cornwall Electric.

In June 2015 and July 2015 the Corporation sold its non-regulated hydro generation assets in Upstate New York and Ontario, respectively.

Market and Sales

Energy sales from non-regulated generation assets were 844 GWh in 2015 compared to 407 GWh in 2014. Revenue was $107 million in 2015 compared to $38 million in 2014. 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.

The following table compares the composition of Fortis Generation's 2015 and 2014 revenue and energy sales by location.

Non-Regulated - Fortis Generation
Revenue and Energy Sales by Location

	Revenue (%)		**GWh Sales (%)**	
	2015	2014	**2015**	2014
Belize	**28.1**	71.0	**26.8**	60.3
Ontario	**3.6**	13.2	**4.1**	13.2
British Columbia	**67.4**	5.5	**65.6**	8.3
Upstate New York	**0.9**	10.3	**3.5**	18.2
Total	**100.0**	100.0	**100.0**	100.0

Human Resources

As at December 31, 2015, BECOL employed approximately 34 full-time employees, none of whom participate in a collective agreement. Non-regulated generation operations in Ontario and British Columbia are staffed by employees of FortisOntario and FortisBC Inc., respectively.

3.6 Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties and Griffith Energy Services, Inc. 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. Griffith Energy Services, Inc. was sold in March 2014.

Fortis Properties' revenue was $171 million in 2015 compared to $249 million in 2014.

4.0 REGULATION

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. With regulated utilities in nine different jurisdictions, Fortis has significant regulatory expertise.

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 2015 Audited Consolidated Financial Statements.

5.0 ENVIRONMENTAL MATTERS

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 including, but not limited to, wildlife, water and land protection, emissions and the proper storage, transportation, recycling and disposal of hazardous and non-hazardous substances. In addition, federal, provincial and state governments have environmental assessment legislation, which is designed to foster better land-use planning and environmental protection through the identification and mitigation of potential environmental impacts of projects or undertakings prior to and after their commencement. The constant evolution of environmental legislation results in ongoing risks to the Corporation, as its subsidiaries must adjust their business operations to comply.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the: (i) *Canadian Environmental Assessment Act, 2012;* (ii) *Canadian Environmental Protection Act, 1999*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Products Act*; (v) *Canada Wildlife Act*; (vi) *Navigation Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act;* (ix) *Canada Water Act;* (x) *National Fire Code of Canada;* (xi) *Pest Control Products Act and Regulations;* (xii) *PCB Regulations;* (xiii) *Species at Risk Act;* (xiv) *Ozone Depleting Substances Regulations;* (xv) *Indian Act* and the duty to consult and accommodate*;* (xvi) *International River Improvements Act;* and (xvii) *Migratory Birds Convention Act, 1994.*

Several key U.S. federal environmental laws and regulations affecting the operations of UNS Energy and Central Hudson include, but are not limited to, the: (i) *Clean Water Act*; (ii) *Safe Drinking Water Act*; (iii) *Clean Air Act*; (iv) *Endangered Species Act*; (v) *Resource Conservation & Recovery Act*; (vi) *Toxic Substances Control Act*; (vii) *Comprehensive Environmental Response, Compensation, and Liability Act*; (viii) *National Environmental Policy Act*; (ix) *Emergency Planning & Community Right to Know Act*; and (x) *Pollution Prevention Act of 1990*.

Environmental risks affecting the Corporation's utility operations include, but are not limited to: (i) hazards associated with the transportation, storage and handling of large volumes of fuel for fuel-powered electricity generating plants, including leaching of the fuel and other operational by-products into the soil, groundwater, nearby watershed areas and open waters; (ii) risk of spills or leaks of petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) risk related to natural gas discharges; (iv) risk of spills or releases into the environment arising from the improper transportation, storage, handling and disposal of other hazardous substances; (v) GHG and other fuel gas emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (vi) risk of fire; (vii) risk of disruption to vegetation; (viii) risk of contamination of soil and water near chemically treated poles; (ix) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (x) risk of responsibility for remediation of contaminated properties, whether or not such contamination resulted from the Corporation's utility operations.

Air Emissions

In addition to changing air emission standards, the management of GHG emissions is a specific environmental concern of the Corporation's Regulated Utilities in Canada and the United States, primarily due to the uncertainties relating to new and emerging federal, provincial and state GHG laws, regulations and guidelines in Canada and the United States. Governmental policy direction is unfolding; however, it remains to be determined whether a GHG air emissions cap or limit may be imposed and to what extent it will impact the Corporation's utilities. Canada has committed to reduce GHG emissions to 30% below 2005 levels by 2030, and the United States has committed to reduce GHG emissions to 32% below 2005 levels by 2030. Both countries are in the process of imposing sectoral requirements, yet it is not certain how the Corporation's subsidiaries will be impacted.

Regulated Utilities – Canada
In British Columbia, the *Carbon Tax Act, Clean Energy Act, Greenhouse Gas Industrial Reporting and Control Act* and *Greenhouse Gas Reduction Targets Act* and anticipated cap-and-trade regulations specifically affect, or may potentially affect, the operations of FortisBC Energy and FortisBC Electric. To help mitigate uncertainty, FortisBC Energy participates in sector and industry groups in order to monitor the development of emerging regulation and policy.

The Government of British Columbia's Energy Plan and GHG reduction targets present risks and opportunities to FortisBC Energy and, to a lesser degree, FortisBC Electric. These government initiatives continue to place pressure on natural gas consumption and its contribution to GHG emissions. The energy and emissions policy in British Columbia also presents opportunities for FortisBC Energy by creating support for incentives to expand the use of renewable energy (such as biogas), transportation related incentives (LNG/compressed natural gas refuelling) and to expand the Energy Efficiency and Conservation program. In addition, the Renewable and Low Carbon Fuel Requirements Regulation under the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirement) Act* provides FortisBC Energy the opportunity to sell low carbon fuel credits generated from customer offerings. The *Carbon Tax Act* improves the position of natural gas relative to other fossil energy, as the tax is based on the amount of carbon dioxide equivalent emitted per unit energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

In 2011 FortisBC Energy began reporting its GHG emissions pursuant to the reporting regulation under the *Greenhouse Gas Reduction (Cap and Trade) Act.* The *Greenhouse Gas Reduction (Cap and Trade) Act* was repealed effective January 1, 2016 and was replaced by the *Greenhouse Gas Industrial Reporting and Control Act*. FortisBC Energy will continue to report its GHG emissions pursuant to the Greenhouse Gas Emission Reporting Regulation under the *Greenhouse Gas Industrial Reporting and Control Act*. In addition, FortisBC Energy continues to report its GHG emissions under Environment Canada's GHG Program. FortisBC Energy has developed capabilities that will support the management of compliance requirements in an upcoming GHG emissions' trading environment, as government policy in that area evolves.

British Columbia continues to be a participant in the Western Climate Initiative, which expects to implement a cap-and-trade program to reduce GHG emissions. FortisBC Energy is expected to be covered under the program. If implemented, the cap-and-trade program is expected to have a declining cap on emissions that all applicable facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release of GHG emissions over the capped amounts.

The impact of GHG emissions is lower at the Corporation's Canadian regulated electric utilities because their primary business is the distribution of electricity. With respect to FortisAlberta, its operations involve only the distribution of electricity. Additionally, all in-house generating capacity at FortisBC Electric, about 70% at Newfoundland Power, and most of the Corporation's non-regulated generating capacity is hydroelectric, a clean energy source. The 335-MW Waneta Expansion is a clean renewable hydroelectric energy source and came into service in April 2015. Only a small portion of in-house generation at Canadian regulated electric utilities uses diesel fuel. The Corporation's Canadian regulated electric utilities are indirectly impacted, however, by GHG emissions through the purchase of power generated by suppliers using combustible fuel. Such power suppliers are responsible for compliance with carbon dioxide emissions standards and the cost of compliance with such standards is generally flowed through to end-use consumers.

Regulated Utilities – United States

UNS Energy and Central Hudson are subject to regulation by United States federal, state and local authorities related to the environmental effects of their operations. The impact of GHG emissions is lower at Central Hudson because it owns minimal generating capacity and relies on purchased capacity and energy from third-party providers.

UNS Energy owns significant generating assets. In August 2015, the EPA issued carbon emission regulations for existing power plants called the CPP. The CPP targets carbon emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. States are required to develop and submit a final compliance plan, or an initial plan with an extension request, to the EPA by September 2016. TEP will continue to work with other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop the state compliance plans. TEP is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA.

The EPA incorporated the compliance obligations for existing power plants located on Indian nations, like the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a plan or that does not have an EPA or approved state plan. TEP will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at both facilities. TEP has submitted comments on the proposed Federal Plan impacting its facilities, including Four Corners and Navajo stating, among other things, that the EPA should not regulate the greenhouse gases on the Navajo Nation because it is not appropriate or necessary. The reduction of greenhouse gases achieved due to the shutdowns resulting from Regional Haze compliance will be equivalent to those required under the CPP rule. TEP cannot predict the ultimate outcome of these matters.

The Company's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule. In February 2016 the United States Supreme Court granted a stay effectively ordering the EPA to stop CPP implementation efforts until legal challenges to the regulation have been resolved. The ruling introduces uncertainty as to whether and when the states and utilities will have to comply with the CPP. UNS Energy will continue to work with the Arizona Department of Environmental Quality to determine what, if any, actions need to be taken in light of the ruling. UNS Energy anticipates that the ruling will likely delay the requirement to submit a plan or request an extension under the CPP by September 2016.

In 2012 the EPA issued final rules for the control of mercury emissions and other hazardous air pollutants from power plants. TEP's Navajo and Springerville plants must be compliant with these rules by April 2016. TEP is proceeding with its compliance activity at each of its facilities.

In June 2015, the U.S. Supreme Court reversed and remanded the D.C. Circuit Court of Appeals decision in *Michigan v. EPA* to uphold the MATS rules requiring power plants to control mercury and other emissions. The Supreme Court held that the EPA did not adequately consider "costs" before determining that the rules were "appropriate and necessary." At this time, the rules remain in force and effect. TEP will proceed with its planned MATS compliance activity at each of its facilities, which ensures compliance with both the federal and state rule, as applicable.

The EPA's Regional Haze Rules impose emission controls on facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. Complying with the EPA's findings, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of TEP's coal-fired generating facilities or for individual joint owners to continue to participate in the units they own at these power plants.

In April 2015, the EPA issued a final rule requiring all coal ash and other coal combustion residuals to be treated as a solid waste under Subtitle D of the *Resource Conservation and Recovery Act* for disposal in landfills and/or surface impoundments while allowing for the continued recycling of coal ash. TEP does not own or operate any impoundments. Under the rule, the Springerville ash landfill is classified as an existing landfill and is not subject to the lateral expansion requirements. However, TEP will incur additional costs for site preparation and monitoring at Springerville to be fully compliant with the rule. TEP's share of the cost at Springerville is estimated to be US$2 million, the majority of which is expected to be capital expenditures. TEP currently estimates its share of the costs to be US$5 million at Four Corners, US$3 million at Navajo, and less than US$1 million at San Juan, the majority of which are expected to be capital expenditures.

Regulated Utilities – Caribbean

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman and Turks and Caicos Islands, they are less extensive than the laws, regulations and guidelines in Canada and the United States. The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol were extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Under the Kyoto Protocol, the United Kingdom is legally bound to reduce its GHG emissions. As an overseas territory, the Cayman Islands are not required to set a target for emissions reduction but are required to give available national statistics on an annual basis to the United Kingdom which will be added to its inventory and reported to the United Nations Framework Convention on Climate Change Secretariat. Caribbean Utilities continues to supply the Cayman Islands Government with data for the national GHG inventory.

All of the energy requirements of Caribbean Utilities and Fortis Turks and Caicos are sourced from in house diesel-powered generation. The more recently installed generators at Caribbean Utilities and Fortis Turks and Caicos have also been designed to provide an increased output per gallon consumed over the older generators, which generate electricity in a more efficient and environmentally friendly manner. Further, exhaust stacks have been designed and installed so as to maximize sound attenuation and optimize exhaust plume dispersion, thereby improving local air quality in accordance with what the utilities believe to be the best industry practice. The use of diesel oil versus heavy fuel oil also results in significantly lower levels of exhaust emissions.

Enterprise Risk Management

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities.

Each of the Corporation's utilities has either an EMS or comprehensive environmental protocols. Through an EMS and environmental protocols, documented procedures are in place to control activities that can affect the environment. Common elements of the utilities' EMS and environmental protocols include: (i) regular inspections of fuel and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) GHG emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury, where applicable; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs, where applicable; (vi) vegetation management programs; (vii) training and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment and implementation of environmental protection measures; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures. Additionally, Newfoundland Power's EMS addresses water control and dam structure, as well as hydroelectric generating facility operations and the impact of such on fish and the surrounding habitat. FortisBC Electric's EMS addresses the environmental impacts associated with water flows including impacts on fisheries and critical habitats.

FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario have developed their respective EMSs consistent with the guidelines of ISO 14001, an internationally recognized standard for EMSs. Caribbean Utilities operates an EMS associated with its generation operations, which is ISO 14001 certified, and uses an EMS for its T&D operations, which is consistent with ISO 14001 guidelines. Fortis Turks and Caicos' EMS is also expected to be ISO 14001 certified. External and/or internal audits of the EMSs and protocols are performed on a periodic basis. Based on audits last completed, the EMSs continue to be effective, properly implemented and maintained, and materially consistent with ISO 14001 guidelines.

Environmental policies form the cornerstone of the EMSs and UNS Energy and Central Hudson's environmental protocols, and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regularly conduct environmental monitoring and audits of the EMSs and environmental protocols, and strive for continual improvement in environmental performance; (v) regularly set and review environmental objectives, targets and programs; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge of environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

Non-Regulated Generation

Environmental risks associated with the Corporation's non-regulated generation operations are addressed in a similar manner as the Corporation's regulated electric utilities that operate in the same jurisdiction as the non-regulated generation operations.

Remediation and Asset Retirement Obligations

Central Hudson is exposed to environmental contingencies associated with MGPs that it and its predecessors owned and operated to serve their customers' heating and lighting needs from the mid to late 1800s to the 1950s. The New York State Department of Environmental Conservation regulates the timing and extent of remediation of MGP sites in New York State. As at December 31, 2015, Central Hudson has recognized approximately US$92 million in associated MGP environmental remediation liabilities. As approved by the New York State Public Service Commission, the company is currently permitted to recover MGP site investigation and remediation costs in customer rates. For additional information, refer to the "3.1.2 Central Hudson" section of this 2015 Annual Information Form.

The Corporation has asset retirement obligations as disclosed in the notes to its 2015 Audited Consolidated Financial Statements. As at December 31, 2015, a liability of $49 million in asset retirement obligations at UNS Energy, Central Hudson and FortisBC Electric has been recognized. With the exception of those asset retirement obligations recognized at UNS Energy, Central Hudson and FortisBC Electric, liabilities with respect to asset retirement obligations associated with the removal of PCB-contaminated oil from electrical equipment at Central Hudson, FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric have not been recorded in the Corporation's 2015 Audited Consolidated Financial Statements, as they were determined to be immaterial to the Corporation's consolidated results of operations, cash flows or financial position. The utilities have ongoing programs to identify and replace transformers which are at risk of spillage of oil, and PCBs continue to be removed from service and safely disposed of in compliance with applicable laws and regulations.

Costs and Oversight

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of EMSs and protocols), compliance with environmental laws, regulations and guidelines, and environmental damage did not have a material impact on the Corporation's consolidated results of operations, cash flows or financial position during 2015 and, based on current laws, facts and circumstances, are not expected to have a material effect in 2016. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable. 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 eligible for recovery in customer rates. Fortis believes that the Corporation and its subsidiaries are materially compliant with the environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

TEP has in place an Environmental Compliance Adjustor, as approved by the ACC, which allows for the recovery of certain capital carrying costs to comply with government-mandated environmental regulations between rate cases.

Oversight of environmental matters is performed at the subsidiary level with regular reporting of environmental matters to the respective subsidiary's Board of Directors.

Sustainability and Efficiency Initiatives

The Fortis utilities have various initiatives focused on clean energy to reduce GHG emissions, including hydroelectric, solar power, wind energy, natural gas and renewable natural gas. Each utility also has implemented energy efficiency programs directed at customers, which help in reducing air emissions and water usage. Further information on how Fortis is managing its impact on the environment will be contained in the Corporation's Environmental Report to be dated on or about March 31, 2016 and published on the Corporation's website at www.fortisinc.com.

Each of the Corporation's Canadian Regulated Electric Utilities that is a member of the CEA is an active participant in the CEA's Sustainable Electricity Program, which was launched in 2009. Participants in the program commit to continuous improvement of their environmental management and performance including reporting annually on environmental and other performance indicators.

For further information on the Corporation's environmental risk factors, refer to the "Business Risk Management - Environmental Risks" section of the Corporation's MD&A.

6.0 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.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

As at February 17, 2016, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share (1)
Common Shares	281,854,344	One
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None
First Preference Shares, Series H (2)	7,024,846	None
First Preference Shares, Series I (2)	2,975,154	None
First Preference Shares, Series J	8,000,000	None
First Preference Shares, Series K	10,000,000	None
First Preference Shares, Series M	24,000,000	None

(1) *The First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive, and whether or not such dividends have been declared.*

(2) *On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. As a result of the conversion, Fortis has issued and outstanding 7,024,846 First Preference Shares, Series H and 2,975,154 First Preference Shares, Series I.*

Dividend Policy
Fortis has targeted annual average dividend growth of 6% through 2020. 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 plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance. The following table summarizes the cash dividends declared per share for each of the Corporation's class of shares for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2015**	**2014**	**2013**
Common Shares	**$1.43**	$1.30	$1.25
First Preference Shares, Series C [(1)]	**-**	-	$0.4862
First Preference Shares, Series E	**$1.2250**	$1.2250	$1.2250
First Preference Shares, Series F	**$1.2250**	$1.2250	$1.2250
First Preference Shares, Series G [(2)]	**$0.9708**	$0.9708	$1.1416
First Preference Shares, Series H [(3)]	**$0.7344**	$1.0625	$1.0625
First Preference Shares, Series I [(3)]	**$0.3637**	-	-
First Preference Shares, Series J	**$1.1875**	$1.1875	$1.1875
First Preference Shares, Series K [(4)]	**$1.0000**	$1.0000	$0.6233
First Preference Shares, Series M [(5)]	**$1.0250**	$0.4613	-

(1) *In July 2013 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series C.*
(2) *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.*
(3) *The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020. The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.*
(4) *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.*
(5) *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.

In September 2015 Fortis increased its dividend per common share over 10% to $0.375 per share, or $1.50 on an annualized basis. In December 2015 the Board declared a fourth quarter 2015 dividend on the Common Shares and the First Preference Shares, Series E, F, G, H, I, J, K and M in accordance with the applicable annual prescribed rate to be paid on March 1, 2016 to holders of record as of February 17, 2016.

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.

First Preference Shares, Series E
Holders of the 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. The Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. The Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradeable Common Shares of the Corporation. The number of Common Shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares at such time. On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradeable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95% of the then-current market price of the Common Shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F
Holders of the 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. The Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time at $25.00 per share if redeemed on or after December 1, 2015 plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G
Holders of the 9,200,000 First Preference Shares, Series G were entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. The annual fixed dividend rate per share for the First Preference Shares, Series G was reset to $0.9708 per share per annum for the five-year period from and including September 1, 2013 to but excluding September 1, 2018. For each five-year period after that date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 2.13%. On September 1, 2018, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time, or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series H
Holders of the 7,024,846 First Preference Shares, Series H are entitled to receive fixed cumulative preferential cash dividends at a rate of $0.6250 per share per annum for each year up to but excluding June 1, 2020. For each five-year period after that date, the holders of First Preference Shares, Series H are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 1.45%.

On each Series H Conversion Date, being June 1, 2015, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series H, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series H Conversion Date, the holders of First Preference Shares, Series H, have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I.

On any First Preference Shares, Series H Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series H outstanding, such remaining First Preference Shares, Series H will automatically be converted into an equal number of First Preference Shares, Series I.

First Preference Shares, Series I
Holders of the 2,975,154 First Preference Shares, Series I are entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board of Directors of the Corporation, in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00, for the five-year period beginning after June 1, 2015. 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%.

On each First Preference Shares, Series I Conversion Date, being June 1, 2020, and June 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after June 1, 2015, that is not a First Preference Shares, Series I Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series I at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series I Conversion Date, the holders of First Preference Shares, Series I have the option to convert any or all of their First Preference Shares, Series I into an equal number of First Preference Shares, Series H.

On any First Preference Shares, Series I Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series I outstanding, such remaining First Preference Shares, Series I will automatically be converted into an equal number of First Preference Shares, Series H. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series I or less than 1,000,000 First Preference Shares, Series H outstanding then no automatic conversion would take place.

First Preference Shares, Series J
Holders of the 8,000,000 First Preference Shares, Series J are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.1875 per share per annum. On or after December 1, 2017, the Corporation may, at its option, redeem for cash the First Preference Shares, Series J, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2018; at $25.75 per share if redeemed on or after December 1, 2018 but before December 1, 2019; at $25.50 per share if redeemed on or after December 1, 2019 but before December 1, 2020; at $25.25 per share if redeemed on or after December 1, 2020 but before December 1, 2021; and at $25.00 per share if redeemed on or after December 1, 2021 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series K
Holders of the 10,000,000 First Preference Shares, Series K are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0000 per share per annum for each year up to but excluding March 1, 2019. For each five-year period after that date, the holders of First Preference Shares, Series K are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 2.05%.

On each Series K Conversion Date, being March 1, 2019, and March 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series K, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series K Conversion Date, the holders of First Preference Shares, Series K have the option to convert any or all of their First Preference Shares, Series K into an equal number of cumulative redeemable floating rate First Preference Shares, Series L.

Holders of the First Preference Shares, Series L will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada treasury bills plus 2.05%.

On each First Preference Shares, Series L Conversion Date, being March 1, 2024, and March 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series L at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after March 1, 2019, that is not a First Preference Shares, Series L Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series L at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series L Conversion Date, the holders of First Preference Shares, Series L have the option to convert any or all of their First Preference Shares, Series L into an equal number of First Preference Shares, Series K.

On any First Preference Shares, Series K Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series K outstanding, such remaining First Preference Shares, Series K will automatically be converted into an equal number of First Preference Shares, Series L. On any First Preference Shares, Series L Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series L outstanding, such remaining First Preference Shares, Series L will automatically be converted into an equal number of First Preference Shares, Series K. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series L or less than 1,000,000 First Preference Shares, Series K outstanding then no automatic conversion would take place.

First Preference Shares, Series M
Holders of the 24,000,000 First Preference Shares, Series M are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.0250 per share per annum for each year up to but excluding December 1, 2019. For each five-year period after that date, the holders of First Preference Shares, Series M are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada bond yield on the applicable reset date plus 2.48%.

On each Series M Conversion Date, being December 1, 2019, and December 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series M, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each Series M Conversion Date, the holders of First Preference Shares, Series M have the option to convert any or all of their First Preference Shares, Series M into an equal number of cumulative redeemable floating rate First Preference Shares, Series N.

Holders of the First Preference Shares, Series N will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada treasury bills plus 2.48%.

On each First Preference Shares, Series N Conversion Date, being December 1, 2024, and December 1 every five years thereafter, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series N at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On any date after December 1, 2019, that is not a First Preference Shares, Series N Conversion Date, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series N at a price of $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption. On each First Preference Shares, Series N Conversion Date, the holders of First Preference Shares, Series N have the option to convert any or all of their First Preference Shares, Series N into an equal number of First Preference Shares, Series M.

On any First Preference Shares, Series M Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series M outstanding, such remaining First Preference Shares, Series M will automatically be converted into an equal number of First Preference Shares, Series N. On any First Preference Shares, Series N Conversion Date, if the Corporation determines that there would be less than 1,000,000 First Preference Shares, Series N outstanding, such remaining First Preference Shares, Series N will automatically be converted into an equal number of First Preference Shares, Series M. However, if such automatic conversions would result in less than 1,000,000 First Preference Shares, Series N or less than 1,000,000 First Preference Shares, Series M outstanding then no automatic conversion would take place.

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 billion unsecured committed revolving corporate credit facility, maturing in July 2020, that is available for general corporate purposes. The Corporation has the ability to increase this facility to $1.3 billion. As of December 31, 2015, the Corporation has not yet exercised its option for the additional $300 million. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 65% at any time.

As at December 31, 2015 and 2014, the Corporation was in compliance with its debt covenant restrictions pertaining to dividend distributions, as described above.

8.0 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 17, 2016.

Fortis Credit Ratings			
Company	**DBRS**	**S&P**	**Moody's**
Fortis (1)	A (low), Under Review - Negative (unsecured debt)	BBB+, Negative (unsecured debt)	N/A
Caribbean Utilities (2)	A (low), Stable (senior unsecured debt)	A-, Negative (senior unsecured debt)	N/A
Central Hudson (2) (3)	N/A	A, Negative (unsecured debt)	A2, Stable (unsecured debt)
FortisBC Energy	A, Stable (secured & unsecured debt)	N/A	A1/A3, Stable (secured/unsecured debt)
FortisAlberta (2)	A (low), Stable (senior unsecured debt)	A-, Negative (senior unsecured debt)	N/A
FortisBC Electric	A (low), Stable (secured & unsecured debt)	N/A	Baa1, Stable (unsecured debt)
Fortis Turks and Caicos	N/A	BBB, Stable (senior unsecured debt)	N/A
Maritime Electric (2)	N/A	A, Negative (senior secured debt)	N/A
Newfoundland Power	A, Stable (first mortgage bonds)	N/A	A2, Stable (first mortgage bonds)
TEP (2)	N/A	BBB+, Negative (unsecured debt)	A3, Stable (senior unsecured debt)
UNS Energy	N/A	N/A	Baa1, Stable (senior secured debt)

(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.*

(2) *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.*

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

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.

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 rating 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 pays each of DBRS, S&P and Moody's an annual monitoring fee and a one-time fee in connection with each rated issuance. In 2015, Fortis also paid fees to S&P and Moody's in respect of certain advisory services provided in connection with the pending acquisition of ITC. No such fees were paid in 2014.

9.0 MARKET FOR SECURITIES

The Common Shares; First Preference Shares, Series E; 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, FTS.PR.E, 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 trading volumes for the Common Shares; First Preference Shares, Series E; 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, 2015.

Fortis
2015 Trading Prices and Volumes

	Common Shares			First Preference Shares, Series E		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	42.23	38.77	14,559,158	26.08	25.75	20,889
February	42.23	38.32	15,673,004	26.04	25.58	25,379
March	40.29	38.36	18,477,567	25.86	25.63	54,230
April	39.90	38.05	9,767,559	25.80	25.60	54,105
May	39.49	37.12	11,546,629	25.90	25.59	24,900
June	38.49	34.45	15,119,531	25.80	25.55	16,200
July	38.46	35.08	11,661,513	25.75	25.45	18,387
August	38.75	34.16	14,095,079	25.69	25.20	16,415
September	38.17	34.20	17,476,551	25.47	25.18	95,148
October	40.14	37.18	15,692,958	25.47	25.30	128,932
November	38.60	36.35	12,504,209	25.49	25.06	32,705
December	38.26	35.51	15,464,056	25.35	25.16	360,105

Fortis 2015 Trading Prices and Volumes						
	First Preference Shares, Series F			First Preference Shares, Series G		
Month	High ($)	Low ($)	Volume	High ($)	Low ($)	Volume
January	25.22	24.51	38,138	25.46	23.26	70,820
February	25.68	24.86	30,672	24.18	23.06	81,535
March	25.24	24.84	48,096	24.47	23.53	248,758
April	25.10	24.36	71,811	23.71	20.84	192,548
May	25.00	24.11	63,091	22.50	21.36	170,316
June	24.51	23.20	55,565	22.17	21.35	94,522
July	24.30	23.52	64,713	21.94	19.95	83,440
August	23.97	21.64	54,337	20.36	16.62	137,163
September	23.07	21.60	210,994	19.26	16.37	280,932
October	22.74	21.20	92,747	19.19	15.90	282,181
November	23.55	21.95	128,647	19.96	17.78	280,941
December	23.71	21.65	87,471	18.49	15.57	374,203
	First Preference Shares, Series H (1)			First Preference Shares, Series I (1)		
Month	High ($)	Low ($)	Volume	High ($)	Low ($)	Volume
January	19.59	16.84	405,862	-	-	-
February	17.29	16.50	219,928	-	-	-
March	16.97	16.05	402,886	-	-	-
April	16.80	15.20	892,668	-	-	-
May	17.10	15.90	233,282	-	-	-
June	17.00	16.05	204,409	17.16	15.61	31,999
July	17.23	16.09	343,502	17.00	15.50	18,950
August	16.55	14.01	293,047	16.10	13.00	20,650
September	15.64	13.00	76,007	14.26	12.10	35,030
October	14.70	13.60	138,311	13.35	12.00	49,072
November	15.70	13.95	110,962	13.75	12.00	75,755
December	14.81	12.75	145,156	13.00	10.92	101,208
	First Preference Shares, Series J			First Preference Shares, Series K		
Month	High ($)	Low ($)	Volume	High ($)	Low ($)	Volume
January	25.13	24.16	117,712	25.53	23.30	89,307
February	25.50	24.80	130,658	24.49	23.15	153,649
March	25.37	24.75	123,776	24.20	23.54	175,640
April	25.12	24.25	168,938	23.90	20.19	219,961
May	25.05	24.00	113,793	22.98	21.48	113,621
June	24.55	23.29	74,548	22.00	20.81	155,165
July	24.40	23.29	58,285	21.90	20.84	158,790
August	23.23	21.20	64,228	21.65	17.90	142,852
September	22.49	21.00	67,129	19.98	15.92	368,777
October	22.45	20.58	78,940	20.04	16.01	340,911
November	22.85	21.23	112,115	20.49	18.52	404,180
December	23.00	20.80	76,388	19.39	16.56	314,369

	First Preference Shares, Series M		
Month	High ($)	Low ($)	Volume
January	25.75	24.26	435,010
February	25.30	24.50	245,579
March	25.34	24.60	331,494
April	25.05	23.26	1,095,659
May	25.46	24.51	550,788
June	24.80	23.48	375,183
July	24.06	22.38	297,623
August	23.77	19.63	178,882
September	22.40	19.40	310,304
October	21.72	17.18	401,744
November	22.83	19.85	311,587
December	21.19	17.90	792,543

(1) *2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I on June 1, 2015. As a result of the conversion, Fortis has issued and outstanding 7,024,846 First Preference Shares, Series H and 2,975,154 First Preference Shares, Series I.*

10.0 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 chart sets out the name and municipality of residence of each of the Directors of Fortis as of February 17, 2016, and indicates their principal occupations within the five preceding years. Each Director's current term expires at the close of the May 5, 2016 annual meeting of shareholders. Paul J. Bonavia, who was elected to the Board of the Corporation in May 2015, resigned from the Board effective February 8, 2016 in order to remain in compliance with the rules of another entity of which he is a director. These rules would not permit Mr. Bonavia to serve as a director of Fortis following the announcement by the Corporation that it has entered into an agreement to acquire ITC.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
TRACEY C. BALL *(1)* Edmonton, Alberta	Ms. Ball, 58, joined the Fortis Board in May 2014. She retired in September 2014 as Executive Vice President and Chief Financial Officer of Canadian Western Bank Group. Prior to joining a predecessor bank to Canadian Western Bank in 1987, she worked in public accounting and consulting. 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 currently serves on the City of Edmonton LRT Governance Board. Ms. Ball graduated from Simon Fraser University with a Bachelor of Arts (Commerce). She is a member of the Chartered Professionals Accountants of Canada, the Institute of Chartered Accountants of Alberta, and the Association of Chartered Professional Accountants of British Columbia. Ms. Ball holds an ICD.D designation from the Institute of Corporate Directors. She serves as a director of FortisAlberta and is Chair of that company's Audit Committee. She does not serve as a director of any other reporting issuer.
PIERRE J. BLOUIN *(3)* Ile Bizard, Quebec	Mr. Blouin, 58, joined the Fortis Board in May 2015. He was Chief Executive Officer of Manitoba Telecom Services, Inc. until his retirement in December 2014. Prior to joining Manitoba Telecom Services, Inc. as its Chief Executive Officer in 2005, Mr. Blouin held various executive positions in the Bell Canada group of companies, including Group President, Consumer Markets for Bell Canada, Chief Executive Officer of BCE Emergis, Inc. and CEO of Bell Mobility. Mr. Blouin graduated from Hautes Etudes Commerciales with a Bachelor of Commerce in Business Administration. He is a Fellow of Purchasing Management Association of Canada and a Fellow of the Institute of Bankers (Canada). Mr. Blouin was appointed to the Human Resources Committee on May 7, 2015. He does not serve as a director of any other reporting issuer.
PETER E. CASE *(1) (2)* Kingston, Ontario	Mr. Case, 61, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and selected U.S. pipeline and energy utilities was consistently rated among the top rankings. Mr. Case was awarded a Bachelor of Arts and an MBA from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. He was first elected to the Board in May 2005 and has been Chair of the Audit Committee of the Board since March 2011. Mr. Case was a Director of FortisOntario from 2003 through 2010 and served as Chair of the FortisOntario Board from 2009 through 2010. He does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
MAURA J. CLARK (1) New York, New York	Ms. Clark, 57, joined the Fortis Board in May 2015. She 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, from 2007. 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. Ms. Clark was appointed to the Audit Committee in May 2015 upon her election to the Board. Ms. Clark also serves as a director of Elizabeth Arden, Inc.
IDA J. GOODREAU (2) (3) Bowen Island, British Columbia	Ms. Goodreau, 64, is a past President and Chief Executive Officer of LifeLabs. Prior to joining LifeLabs in March 2009, she served as President and Chief Executive Officer of Vancouver Coastal Health Authority from 2002. Ms. Goodreau has held senior leadership roles in several Canadian and international pulp and paper and natural gas companies. She was awarded an MBA and a Bachelor of Commerce, Honours, degree from the University of Windsor and a Bachelor of Arts (English and Economics) from the University of Western Ontario. She has served on numerous private and public sector boards and has been 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. She was first elected to the Board in May 2009. Ms. Goodreau does not serve as a director of any other reporting issuer.
DOUGLAS J. HAUGHEY (1) (3) Calgary, Alberta	Mr. Haughey, 59, from August 2012 through May 2013, was Chief Executive Officer of The Churchill Corporation, a commercial construction and industrial services company focused on the western Canadian market. From 2010 through its successful sale to Pembina Pipeline in April 2012, he served as President and Chief Executive Officer of Provident Energy Ltd., an owner/operator of natural gas liquids midstream facilities. From 1999 through 2008, he held several executive roles with Spectra Energy and predecessor companies. Mr. Haughey had overall responsibility for its western Canadian natural gas midstream business, was President and Chief Executive Officer of Spectra Energy Income Fund and also led Spectra's strategic development and mergers and acquisitions teams based in Houston, Texas. He graduated from the University of Regina with a Bachelor of Administration and from the University of Calgary with an MBA. Mr. Haughey also holds an ICD.D designation from the Institute of Corporate Directors. He was first elected to the Board in May 2009. Mr. Haughey became a director of FortisAlberta in 2010, and serves as Chair of that Board. Mr. Haughey was appointed Chair of the Human Resources Committee in March 2015. Mr. Haughey is also lead director of Keyera Corporation.
R. HARRY McWATTERS (2) Summerland, British Columbia	Mr. McWatters, 70, is 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. He is the founder and past President of Sumac Ridge Estate Wine Group. Mr. McWatters was first elected to the Board in May 2007. He was a Director of FHI and FortisBC Inc., where he served as Chair from 2006 through 2010. Mr. McWatters does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
RONALD D. MUNKLEY *(2) (3)* Mississauga, Ontario	Mr. Munkley, 70, a Corporate Director, retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. While there he acted as lead advisor on over 175 capital markets and strategic and advisory assignments for North American utility clients. Prior to that he was COO at Enbridge Inc. and Chairman of Enbridge Consumer Gas. Previously he was President and CEO of Consumer Gas where he led the company through deregulation and restructuring in the 1990s. He graduated from Queen's University with a Bachelor of Science (Engineering), Honours. Mr. Munkley is a professional engineer and has completed the Executive and Senior Executive Programs of the University of Western Ontario and the Partners, Directors and Senior Officers Certificate of the Canadian Securities Institute. He was first elected to the Board in May 2009. Mr. Munkley also serves as a director of Bird Construction Inc.
DAVID G. NORRIS *(1) (2) (3)* St. John's, Newfoundland and Labrador	Mr. Norris, 68, a Corporate Director, 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. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board of the Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce, Honours, from Memorial University of Newfoundland and an MBA from McMaster University. He was first elected to the Board in May 2005 and was appointed Chair of the Board in December 2010. Mr. Norris served as Chair of the Audit Committee of the Board from May 2006 through March 2011. He was a director of Newfoundland Power from 2003 through 2010 and served as Chair of that Board from 2006 through 2010. Mr. Norris served as a director of Fortis Properties from 2006 through 2010. He does not serve as a director of any other reporting issuer.
BARRY V. PERRY St. John's, Newfoundland and Labrador	Mr. Perry, 51, 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 joined the Fortis organization in 2000 as Vice President, Finance and Chief Financial Officer of Newfoundland Power. He earned a Bachelor of Commerce from Memorial University of Newfoundland and is a member of the Association of Chartered Professional Accountants of Newfoundland and Labrador. Mr. Perry serves on the Boards of Fortis utilities in British Columbia, Alberta, Arizona and New York. Mr. Perry was appointed to the Board on January 1, 2015, concurrent with his appointment as President and Chief Executive Officer of the Corporation.

(1) *Serves on the Audit Committee.*
(2) *Serves on the Governance and Nominating Committee.*
(3) *Serves on the Human Resources Committee.*

The following table sets out the name and municipality of residence of each of the officers of Fortis as of December 31, 2015, and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
Barry V. Perry St. John's, Newfoundland and Labrador	President and Chief Executive Officer *(1)*
Karl W. Smith St. John's, Newfoundland and Labrador	Executive Vice President, Chief Financial Officer *(2)*
Nora M. Duke St. John's, Newfoundland and Labrador	Executive Vice President, Corporate Services and Chief Human Resource Officer *(3)*
Earl A. Ludlow Paradise, Newfoundland and Labrador	Executive Vice President, Eastern Canadian and Caribbean Operations *(4)*
David C. Bennett St. John's, Newfoundland and Labrador	Vice President, Chief Legal Officer and Corporate Secretary *(5)*
James D. Spinney Mount Pearl, Newfoundland and Labrador	Vice President, Treasurer *(6)*
Jamie D. Roberts Mount Pearl, Newfoundland and Labrador	Vice President, Controller *(7)*
Regan P. O'Dea St. John's, Newfoundland and Labrador	Assistant Corporate Secretary *(8)*

(1) *Mr. Perry was appointed President and Chief Executive Officer, effective January 1, 2015, upon the retirement of Mr. H. Stanley Marshall. Mr. Perry became President of Fortis effective June 30, 2014. Prior to that time, Mr. Perry served as Vice President, Finance and Chief Financial Officer of Fortis since 2004.*

(2) *Mr. Smith was appointed Executive Vice President, Chief Financial Officer, effective June 30, 2014. Prior to that time, Mr. Smith served as President and Chief Executive Officer of FortisAlberta since 2007.*

(3) *Ms. Duke was appointed Executive Vice President, Corporate Services and Chief Human Resource Officer, effective August 1, 2015. Prior to that time, Ms. Duke served as President and Chief Executive Officer of Fortis Properties since 2008.*

(4) *Mr. Ludlow was appointed Executive Vice President, Eastern Canadian and Caribbean Operations, effective August 1, 2014. Prior to that time, Mr. Ludlow served as President and Chief Executive Officer at Newfoundland Power since 2007.*

(5) *Mr. Bennett was appointed Vice President, Chief Legal Officer and Corporate Secretary, effective September 19, 2014. Prior to that time, Mr. Bennett served as Vice President, Operations Support, General Counsel and Corporate Secretary since 2013 and Vice President, General Counsel and Corporate Secretary since 2010 for FortisBC Inc., FortisBC Energy and FHI.*

(6) *Mr. Spinney was appointed Vice President, Treasurer, effective March 20, 2013. Prior to that time, Mr. Spinney served as Manager, Treasury at Fortis since October 2002.*

(7) *Mr. Roberts was appointed Vice President, Controller, effective March 20, 2013. Prior to that time, Mr. Roberts served as Vice President, Finance and Chief Financial Officer of Fortis Properties since July 2008.*

(8) *Mr. O'Dea was appointed Assistant Corporate Secretary effective May 7, 2015, and holds the position of Associate General Counsel since January 2014. Prior to that time, Mr. O'Dea served as Director, Legal and Corporate Services and Corporate Secretary of Johnson Inc. since 2011.*

As at December 31, 2015, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 603,991 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.

11.0 AUDIT COMMITTEE

11.1 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, 2015, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE *(Chair)* Kingston, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was awarded 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 Edmonton, Alberta	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 currently serves on the City of Edmonton LRT Governance Board. 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 New York, New York	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.
DOUGLAS J. HAUGHEY Calgary, Alberta	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 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 St. John's, Newfoundland and Labrador	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 graduated with a Bachelor of Commerce, Honours, from Memorial University of Newfoundland and an MBA from McMaster University.

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*. 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 2015 Audited Consolidated Financial Statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

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;

"**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;

"**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 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 (i) of the Chair of the Committee, or (ii) of any two (2) Members, or (iii) of the External Auditor.

4. 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.

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

6. 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.

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

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.

   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.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus 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 be responsible for the oversight of the Internal Auditor.

2.8. The Committee shall monitor and report on the development of the Enterprise Risk Management Program.

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.

11.3 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.

11.4 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.

Fortis External Auditor Service Fees ($ thousands)		
Ernst & Young LLP	**2015**	**2014**
Audit Fees	5,223	4,601
Audit-Related Fees	870	748
Tax Fees	475	119
Non-Audit Fees	-	48
Total	**6,568**	**5,516**

Audit fees were higher in 2015 than in 2014, mainly due to general increases in fees and the impact of foreign exchange on US dollar-denominated audit fees. The increase in tax fees was largely due to additional work completed on the sale of non-core assets. Ernst & Young LLP did not provide any non-audit services in 2015.

12.0 TRANSFER AGENT AND REGISTRAR

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

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

13.0 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, 2015 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Association of Chartered Professional Accountants of Newfoundland and Labrador.

14.0 ADDITIONAL INFORMATION

Additional financial information is provided in the Corporation's MD&A and 2015 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 and on SEDAR at www.sedar.com.

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, will be contained in the management information circular of Fortis to be 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 the 2015 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.