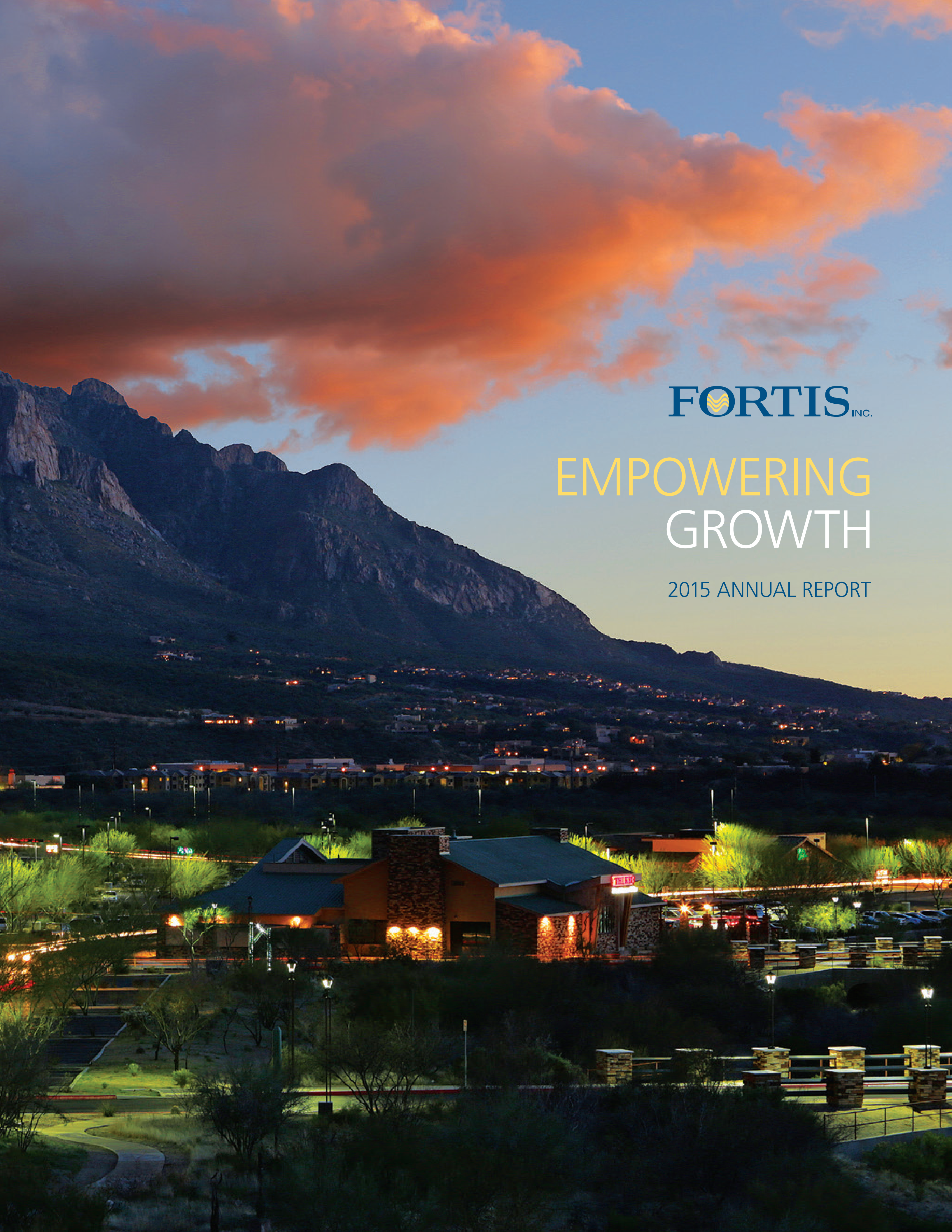


FORTIS INC.

EMPOWERING GROWTH

2015 ANNUAL REPORT

FORTIS INC.

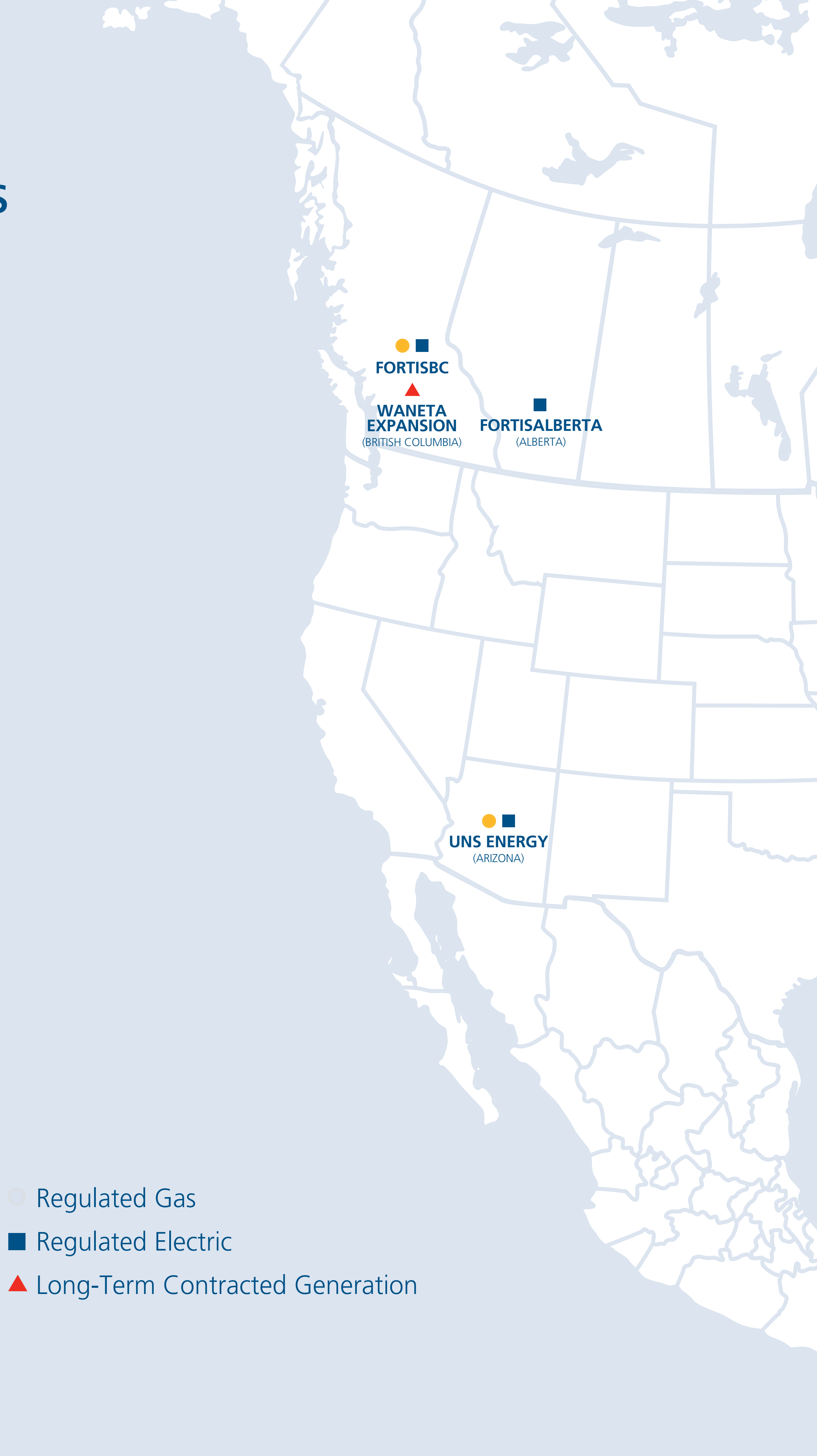
Quick Facts

BASED IN
ST. JOHN'S, NL

9 UTILITY OPERATIONS
IN CANADA, U.S. AND CARIBBEAN

7,700
EMPLOYEES **STRONG**

$29B
TOTAL **ASSETS**

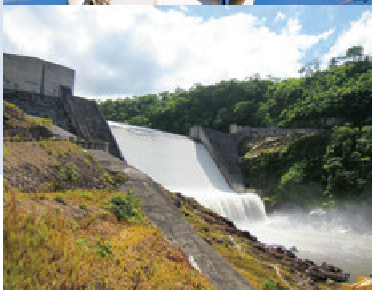


2 **MILLION ELECTRIC**
UTILITY CUSTOMERS

1.2 **MILLION GAS**
UTILITY CUSTOMERS

$10.5B
MARKET CAP
(as of December 31, 2015)

MEMBER OF THE
S&P/TSX 60



Regulated, Low Risk and Diversified

No jurisdiction accounts for more than one-third of total assets or operating earnings.

Business Segments

Regulated

Utility	Customers Electric (#)	Customers Gas (#)	Employees (#)	Peak Demand Electric (MW)	Peak Demand Gas (TJ)	Sales Electric (GWh)	Volumes Gas (PJ)	Earnings ($M)	Total Assets ($B)	Midyear Rate Base ($B)	2016F Capital Program ($M)
UNS Energy	511,000	152,000	2,015	3,267	109	15,366	13	195	8.9	4.8	485
Central Hudson	300,000	79,000	966	1,059	140	5,132	24	58	3.2	1.6	228
FortisBC [(1)]	168,000	982,000	2,127	624	1,074	3,116	186	190	8.1	5.0	428
FortisAlberta	539,000	–	1,162	2,733	–	17,132	–	138	3.8	3.0	441
Eastern Canadian [(2)]	405,000	–	1,033	1,883	–	8,403	–	62	2.3	1.7	174
Caribbean Electric [(3)]	42,000	–	356	139	–	802	–	34	1.3	0.9	127
TOTAL	**1,965,000**	**1,213,000**	**7,659**	**9,705**	**1,323**	**49,951**	**223**	**677**	**27.6**	**17.0**	**1,883**

(1) Includes FortisBC Energy and FortisBC Electric.

(2) Includes Newfoundland Power, Maritime Electric and FortisOntario.

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

Non-Regulated

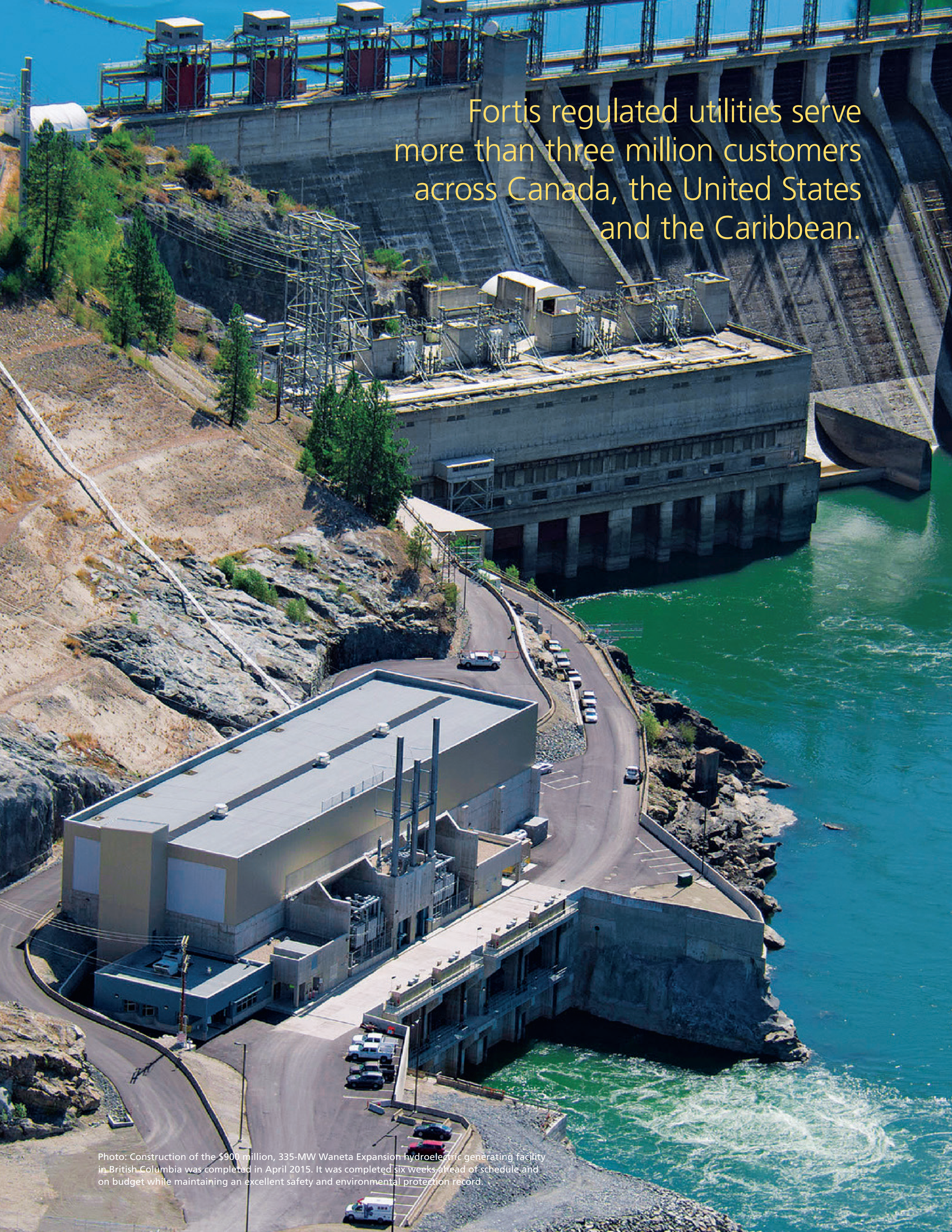
	Generating Capacity (MW)	Employees (#)	Sales Energy (GWh)	Earnings [(2)] ($M)	Total Assets ($B)	2016F Capital Program ($M)
Fortis Generation [(1)]	407	34	844	77	1.0	18 [(3)]

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

(2) Earnings from non-utility operations were $114 million.

(3) Includes forecast capital expenditures of approximately $15 million at Fortis Generation and $3 million at FortisBC Alternative Energy Services Inc., which is reported in the Corporate and Other segment.

All financial information is presented in Canadian dollars.
Information is for the fiscal year ended December 31, 2015 unless otherwise indicated.



Fortis regulated utilities serve more than three million customers across Canada, the United States and the Caribbean.

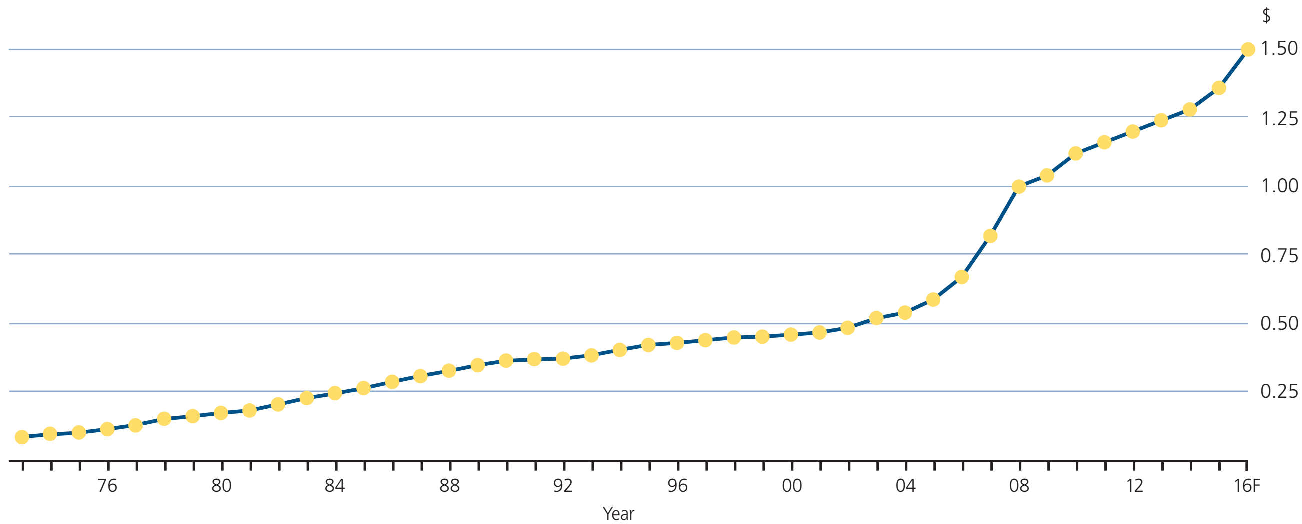
Photo: Construction of the $900 million, 335-MW Waneta Expansion hydroelectric generating facility in British Columbia was completed in April 2015. It was completed six weeks ahead of schedule and on budget while maintaining an excellent safety and environmental protection record.

Photo: Fortis owns and/or operates more than 188,000 kilometres of transmission and distribution lines.

Strong Track Record of Total Shareholder Returns

2015 was the 42nd consecutive year of annual dividend increases and marked the introduction of dividend guidance for the first time, with an annual average dividend growth target of 6% through 2020.

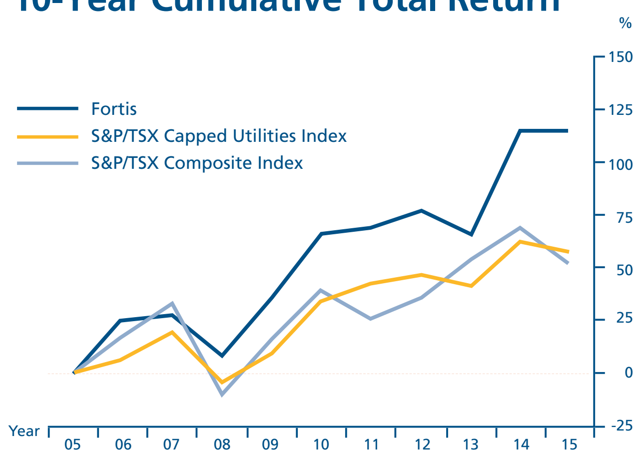
Dividends Paid Per Common Share



Achieved Average Annualized Total Shareholder Return of 8.2% Over the Last 10 Years

The 10-year cumulative total return of 116% for the period ended December 31, 2015 is approximately 60% higher than the performance of the S&P/TSX Capped Utilities and Composite indices.

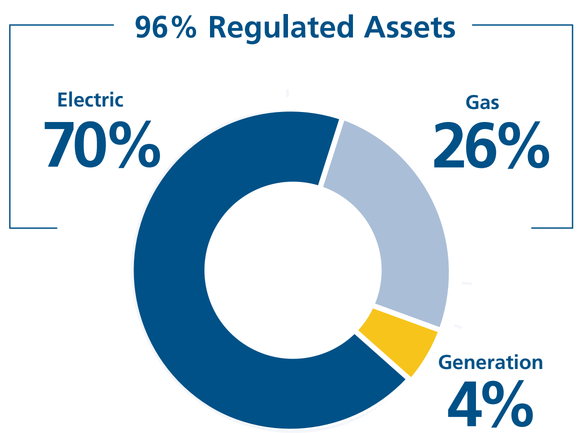
10-Year Cumulative Total Return



Total Assets Increased 9.9%

$29 Billion (as at December 31, 2015)

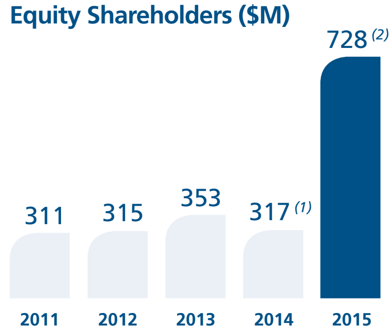
Total Assets



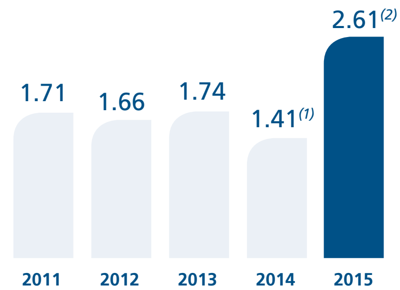
Financial Highlights

Fortis achieved record earnings in 2015, driven by its U.S. utility acquisitions, gains on non-core asset dispositions, completion of the Waneta hydroelectric generating facility (Waneta Expansion) and strong results from its Canadian utilities.

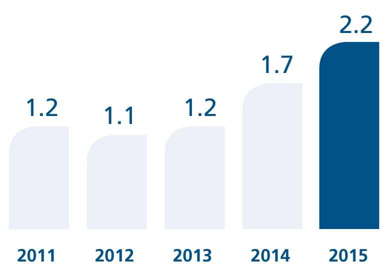
Earnings Attributable to Common Equity Shareholders ($M)



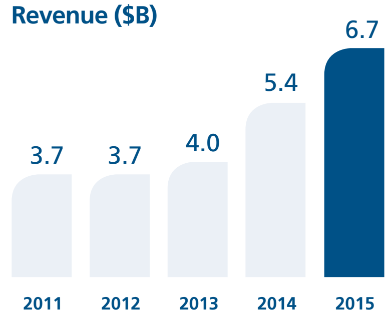
Basic Earnings per Common Share ($)



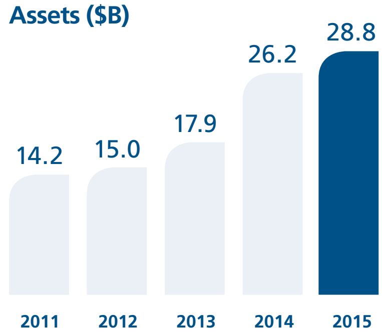
Capital Expenditures ($B)



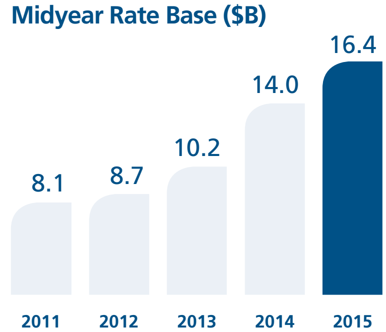
Revenue ($B)



Assets ($B)



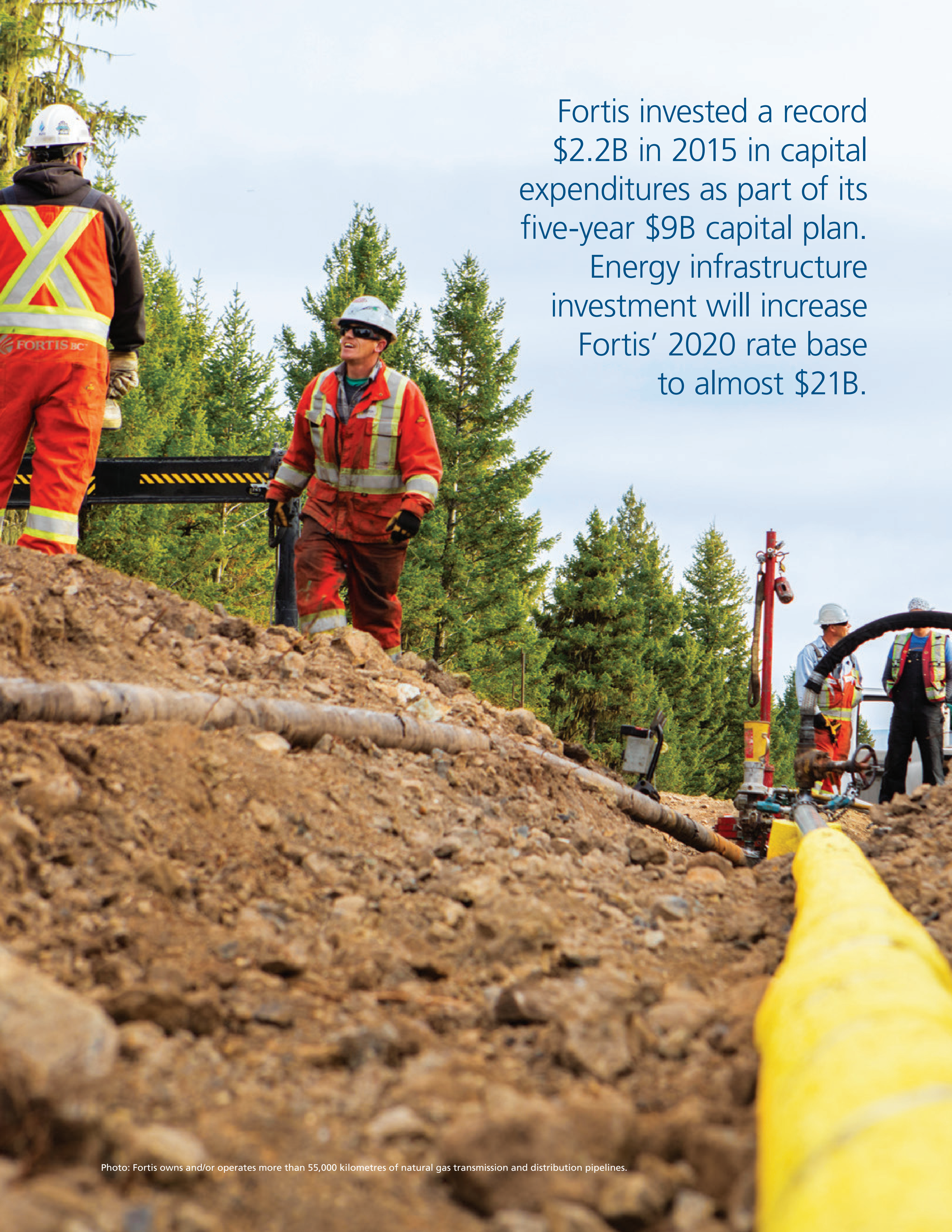
Midyear Rate Base ($B)



(1) Results were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014.

(2) Results were impacted by a full year's contribution from UNS Energy, completion of the Waneta Expansion and non-recurring items, largely associated with gains on the sale of non-core assets.

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



Fortis invested a record $2.2B in 2015 in capital expenditures as part of its five-year $9B capital plan. Energy infrastructure investment will increase Fortis' 2020 rate base to almost $21B.

Photo: Fortis owns and/or operates more than 55,000 kilometres of natural gas transmission and distribution pipelines.

Report to Shareholders

2015 was a remarkable year for Fortis

We advanced our business operationally and strategically, delivered record earnings, raised our dividend for the 42nd consecutive year and introduced dividend growth guidance of 6%, on average, annually through 2020. We successfully executed our annual capital expenditure plan, investing a record $2.2 billion in energy infrastructure. Our 2015 results illustrate the underlying strength of our business model, the breadth and depth of the management team, and our ability to drive performance across the organization.

Ongoing focus – strength & growth in our core business

Our priority continues to be the provision of safe, reliable, cost-effective energy service to our customers and the profitable expansion of our existing operations. We remain focused on executing our capital program and pursuing additional investment opportunities within existing service territories. Our stand-alone operating model and financial strength, driven by a strong balance sheet and investment-grade credit ratings, positions us well for future expansion and leadership in the North American utility sector.

Rate base is expected to be almost $21 billion in 2020

Over the five-year period through 2020, excluding the acquisition of ITC Holdings Corp., our capital program related to our existing operations is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to almost $21 billion in 2020, exclusive of new acquisitions, and produce a five-year compound annual growth rate of approximately 5%.

Fortis remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value.

Barry Perry, President and CEO, Fortis Inc. (left) and David Norris, Chair of the Board, Fortis Inc. (right).

Report to Shareholders

Strong financial performance

We achieved record net earnings of $728 million, or $2.61 per common share. A number of factors drove our strong financial results in 2015. We were successful in selling non-core assets and achieved significant gains on these sales. The acquisition of UNS Energy, which we completed in August 2014, clearly had an important impact on our results, contributing $195 million in earnings. We also benefitted from the completion of the Waneta hydroelectric generating facility (Waneta Expansion), the strength of the US dollar relative to the Canadian dollar, strong results from our Canadian utilities, and the resetting of customer rates at Central Hudson. Adjusted net earnings attributable to common equity shareholders for 2015 were $589 million, or $2.11 per common share, an increase of $195 million, or $0.36 per common share, over 2014. Cash flow from operations totalled $1.7 billion, 70% higher than last year, largely driven by higher cash earnings.

Record capital investment

Consolidated capital expenditures totalled $2.2 billion in 2015, representing the largest capital program in the history of Fortis. These investments fuel growth in our rate base, which midyear was $16.4 billion. The majority of our capital projects are small and highly executable, but in 2015 we did successfully complete our largest project to date: the $900 million, 335-megawatt (MW) Waneta Expansion. We also continued to advance other projects across our businesses, including the following key projects:

FortisBC Energy – Tilbury LNG Facility Expansion

Construction efforts in 2015 focused on building the storage tank and liquefaction process areas. We expect the project, which includes a second liquefied natural gas (LNG) tank and a new liquefier, to be in service around the end of 2016. Total project costs to the end of 2015 were approximately $326 million, with $181 million invested in 2015.

FortisAlberta – Pole-Management Program

During 2015 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program. The total capital cost of the program through 2020 is expected to be approximately $336 million, with $41 million invested in 2015, for a total of $200 million to date.

UNS Energy – Residential Solar Program and Pinal Transmission Project

UNS Energy, which ranks among the top 10 utilities in the United States for installing new solar capacity and per-capita additions to its solar energy portfolio, advanced its Residential Solar Program in partnership with local solar companies. This partnership allows UNS Energy to own and install rooftop solar systems for residential customers. The total capital cost of the program through 2020 is expected to be approximately US$82 million, with US$16 million to be invested in 2016. UNS Energy also completed the Pinal Transmission Project in 2015 at a total project cost of US$79 million. The project consisted of the construction of a 500-kilovolt (kV) transmission line in Pinal County that will increase UNS Energy's import capacity from Gila River Unit 3 and the Palo Verde trading hub.

Significant progress in renewable energy

In partnership with Columbia Power Corporation and Columbia Basin Trust, Fortis completed the 335-MW Waneta Expansion near Trail, British Columbia. The output of the Waneta Expansion is being sold to BC Hydro and FortisBC under 40-year contracts. The Waneta Expansion has added a second powerhouse that shares the existing hydraulic head and generates clean, renewable, cost-efficient power from water that would otherwise be spilled. The project included construction of a 10-kilometre, 230-kV transmission line and provides enough energy to power approximately 60,000 homes per year. It was completed six weeks ahead of schedule and on budget while maintaining an excellent safety and environmental protection record.

Solid credit metrics

Maintaining solid investment-grade credit ratings through a strong balance sheet and ample liquidity is a priority for us. As of year-end, we had unused consolidated credit facilities that totalled approximately $2.4 billion.

Underlying confidence in our business allows us to initiate dividend guidance

The strength of our business and the confidence in our future allowed us in 2015 to raise our dividend twice as well as initiate dividend guidance. We ended the year with a quarterly dividend that translates into an annualized dividend of $1.50 per share, and we are targeting average annualized dividend growth of 6% through 2020. We are proud of our 42-year track record of annual dividend increases, and believe that our low-risk, predictable and diversified business will allow us to meet our dividend growth targets.

Sharpening our focus on our core regulated utility businesses

After two major acquisitions in the previous two years, we spent 2015 focusing on our base business and integrating our Arizona utility, UNS Energy. As part of sharpening our focus on our core utility business in 2015, we divested our commercial real estate and hotel business, as well as some small non-regulated generation assets. We realized proceeds of almost $900 million from these sales, which were used primarily to repay credit facility borrowings – largely associated with the acquisition of UNS Energy.

We continue to look for investment opportunities in energy-related infrastructure

While Fortis expects long-term sustainable growth in rate base, earnings, and shareholder returns from investment in its existing utility operations, it is also committed to identifying and executing on opportunities for additional growth through investments in existing service territories.

We delivered on this commitment with the announcement in December of the acquisition of the Aitken Creek Gas Storage Facility (Aitken Creek) for approximately US$266 million. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada's natural gas transmission network. We anticipate that this transaction will close in the first half of 2016.

Active regulatory calendar

Fortis focuses on maintaining constructive regulatory relationships and outcomes across its utilities. Our regulatory calendar remains active. There were some important decisions and advancements in 2015, including a three-year rate settlement that saw a resetting of customer rates effective July 1 at Central Hudson; as well as decisions on Capital Tracker Applications and a Generic Cost of Capital Proceeding at FortisAlberta.

We expect 2016 to also be an active year, with the advancement of the general rate applications at Tucson Electric Power for new retail rates effective January 1, 2017 and at Newfoundland Power for new rates effective July 1, 2016; Reforming the Energy Vision proceeding progressing in New York State; Generic Cost of Capital Proceedings in British Columbia and Alberta; and a Capital Tracker application at FortisAlberta.

Empowering leaders to grow the business

We continue to empower the leaders of our utilities to drive performance, discover new investment opportunities and foster talent. Enterprise-wide talent management and development has been elevated to a strategic priority as we prepare for the next stage of growth at Fortis. As part of this initiative we have appointed Nora Duke, Executive Vice President, Corporate Services and Chief Human Resource Officer. Nora is a veteran of Fortis, having spent almost 30 years with the organization, most recently as President and Chief Executive Officer of Fortis Properties.

Environmental sustainability – Fortis at the forefront of industry change

The North American electric utility industry continues to evolve and change. The most notable changes include a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. With increasing levels of solar usage and plans for a significant shift away from coal generation in Arizona, as well as major regulatory reform ongoing in New York, Fortis subsidiaries in the United States are at the centre of many of the key trends within the industry.

Our strategy is to ensure that we are well positioned to embrace these opportunities, facilitate public policy objectives, and collaborate with customers and regulators on outcomes that preserve the strength of the grid and role of the incumbent utilities. This, in turn, will allow us to deliver on our growth objectives.

Report to Shareholders

Acquisition of ITC Holdings Corp.

Fortis has grown its business through strategic acquisitions that have contributed to the strong organic growth of the Corporation over the past decade. On February 9, 2016, Fortis announced it would be acquiring ITC Holdings Corp. (ITC) in a transaction valued at approximately US$11.3 billion. We expect this accretive acquisition will support our growth strategy, as well as further strengthen and diversify our business.

ITC is the largest independent pure-play electric transmission company in the United States. The Michigan-based company owns and operates high-voltage transmission facilities, serving a combined peak load exceeding 26,000 MW along approximately 15,600 circuit miles of transmission line. ITC's rate base is expected to grow at a compound annual rate of approximately 7.5% through 2018, and its rates are regulated by the Federal Energy Regulatory Commission (FERC), which has been one of the most consistently supportive regulators in North America, providing reasonable returns and equity ratios.

The combined company will be one of the largest investor-owned North American utilities, with an expected consolidated 2016 midyear rate base of $26 billion. Following the completion of the acquisition, our utilities in the United States will represent approximately 60% of our regulated earnings and assets. As part of the ITC transaction, Fortis expects to list its common shares on the New York Stock Exchange (NYSE) under the ticker symbol FTS. Listing on the NYSE will provide access to larger pools of capital and likely increase trading of our shares.

Shareholders can expect to hear more from us in 2016 as we move through key milestones leading up to closing, including shareholder approval for both companies and various regulatory approvals. Closing is expected to occur in late 2016.

Looking forward

Fortis is continuing on its sound and successful, time-tested strategy: a well-managed, low-risk, highly diversified utility that has a measured and disciplined approach to growth.

Fortis remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value. We measure our financial and operational performance primarily through growth in earnings per common share and total shareholder return.

Over the 10-year period ended December 31, 2015, earnings per common share of Fortis grew at a compound annual growth rate of 4.6%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 8.2%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite indices, which delivered average annualized performance of 4.6% and 4.2%, respectively, over the same period.

Clearly, we are confident about the future of Fortis. Our success to date and our future prospects have, and will always be, the result of the hard work of our talented and dedicated people, and to the strong corporate culture of Fortis. To each and every one of our employees, your hard work and commitment to customers underpins the success of Fortis. Thank you for your ongoing contribution.

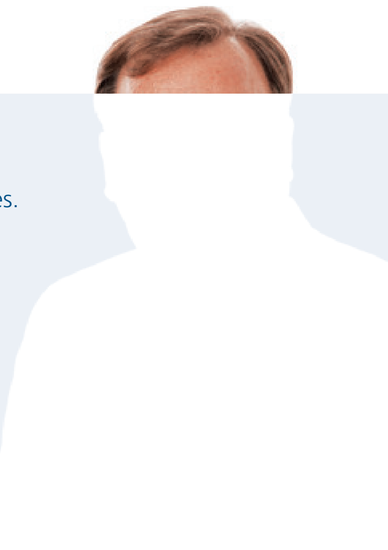
It is with regret that we acknowledge the resignation of Paul Bonavia from our Board in February 2016. Paul withdrew from the Fortis Board in order to remain in compliance with the rules of another entity of which he is a director. We wish to express our genuine gratitude to Paul for his insight and valuable contribution to the Board and extend our best wishes to him for the future. Finally, we also extend our sincerest appreciation to all of our colleagues on the Board of Directors for your continuing dedication, insight and support.

On behalf of the Board of Directors,

David G. Norris
Chair of the Board,
Fortis Inc.

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

Fortis Inc. – H. Stanley Marshall Memorial Scholarship



H. Stanley Marshall retired as President and CEO from Fortis in 2014, after building a formidable legacy at Fortis. He has left an indelible imprint on our culture, vision and values.

During 2015 Fortis established an endowed scholarship in recognition of his contribution to the Corporation's success. The *Fortis Inc. – H. Stanley Marshall Memorial Scholarship* will support undergraduate students from a Caribbean country entering a professional school or faculty at Memorial University of Newfoundland. Fortis has a strong link to the Caribbean through its operations there, beginning in 1999 with the acquisition of an electric utility in Belize.

Honouring Our Past

In keeping with Fortis' proud Newfoundland history and roots, and honouring its provincial heritage, Fortis became a Centennial Leader with a $3.25 million donation to the *Where Once They Stood We Stand* capital campaign.

With this donation, Fortis became the lead corporate supporter to commemorate Newfoundland's contribution to the First World War and the Battle of Beaumont-Hamel. Both the First World War Exhibition and The Rooms Site Courtyard area will serve as a perpetual monument to Newfoundland's contribution to the First World War, and will be dedicated by the Centennial Lead Donors on July 1, 2016 to all those who served overseas and on the home front.

We encourage those of you living here in Newfoundland or visiting to join us and other supporters to open this important monument and honour those who served Newfoundland and the British Empire.

Photo Credit: The Rooms: NA 3106; Opening of the Newfoundland Memorial Park, Beaumont-Hamel, France. 7 June 1925.

Contents

Dated February 17, 2016

FORWARD-LOOKING INFORMATION

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. The MD&A should be read in conjunction with the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2015. Financial information for 2015 and comparative periods contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable 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", "target", "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 based on information currently available. The forward-looking information in the MD&A includes, but is not limited to, statements related to the acquisition of ITC Holdings Corp. ("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 assumption of ITC debt and expected maintenance of investment-grade credit ratings; the impact of the acquisition on the Corporation's earnings, midyear 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 a U.S. Securities and Exchange Commission 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; the annualized 2016 common share dividend; targeted annual dividend growth through 2020; the expectation that there will be a significant reduction in the use of coal in certain of UNS Energy's generating facilities by 2022; the acquisition of a share of Aitken Creek Gas Storage facility, the expected timing, total expected consideration and conditions precedent to the closing of such acquisition, including regulatory approval; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the expectation that midyear rate base will increase from 2016 to 2020; the Corporation's forecast gross consolidated capital expenditures for 2016 and total capital spending over the five-year period from 2016 through 2020; the nature, timing and expected costs of certain capital projects including, without limitation, the Tilbury liquefied natural gas ("LNG") facility expansion, the pipeline expansion to the Woodfibre LNG site, the development of a diesel power plant in Grand Cayman, the Residential Solar Program, the Gas Main Replacement Program, the Lower Mainland System Upgrade, the Pole Management Program, and *additional opportunities including electric transmission, LNG and renewable related infrastructure and generation; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2016 capital expenditure programs, operating and interest costs, and dividend payments; the expected consolidated fixed-term debt maturities and repayments in 2016 and on average annually over the next five years; the expectation that long-term debt will not be settled prior to maturity; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to long terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2016; the intent of management to hedge future exchange rate fluctuations and monitor its foreign currency exposure; the expectation that economic conditions in Arizona will improve; 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; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.*

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; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the realization of additional opportunities including natural gas related infrastructure and generation; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel, coal and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans 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 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 this MD&A 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 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 MD&A 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.

CORPORATE OVERVIEW

Karl Smith, *EVP, CFO, Fortis Inc.*

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 (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 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,323 terajoules.

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

Earnings of regulated utilities may be impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and common equity component of capital structure; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) regulatory lag in the case of a historical test year. When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of the actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Fortis segments its 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 are treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

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

Regulated Utilities

The Corporation's interests in regulated electric and gas utilities are as follows.

Regulated Electric & Gas Utilities – United States

a. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively, the "UNS Utilities"), acquired by Fortis in August 2014.

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 417,000 retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.

   UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to approximately 94,000 retail customers in Arizona's Mohave and Santa Cruz counties.

TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,799 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2015, approximately 43% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility, serving approximately 152,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

b. *Central Hudson:* Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("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. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Regulated Gas Utility – Canadian

FortisBC Energy: Primarily includes FortisBC Energy Inc. ("FortisBC Energy" or "FEI") and, prior to December 31, 2014, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company. FEI is the largest distributor of natural gas in British Columbia, serving approximately 982,000 customers in more than 135 communities. Major areas served by the Company are the Lower Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 539,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 168,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro; the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("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.

c. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("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. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving approximately 78,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. 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 primarily comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power").

Regulated Electric Utilities – Caribbean

The Regulated Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2014 – 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("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 has an installed diesel-powered generating capacity of 132 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("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 have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated – Fortis Generation

Fortis Generation is primarily comprised of long-term contracted generation assets in British Columbia and Belize. Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion. Construction of the Waneta Expansion was completed in April 2015 and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts. The Corporation's 51% controlling ownership interest in the Waneta Expansion is conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest.

Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

As at December 31, 2015, the 16-MW run-of-river Walden hydroelectric generating facility has been classified as held for sale.

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

Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties") and Griffith Energy Services, Inc. ("Griffith"). Fortis Properties completed the sale of its commercial real estate assets in June 2015 and its hotel assets in October 2015. For further information, refer to the "Significant Items" section of this MD&A. Griffith was sold in March 2014.

Corporate and Other

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

CORPORATE STRATEGY

The principal business of Fortis is the ownership and operation of regulated electric and gas utilities. The Corporation remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value. Earnings per common share and total shareholder return are the primary measures of financial performance.

Over the 10-year period ended December 31, 2015, earnings per common share of Fortis grew at a compound annual growth rate of 4.6%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 8.2%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 4.6% and 4.2%, respectively, over the same period.

The Corporation's first priority remains the continued profitable expansion of existing operations. Management remains focused on executing the consolidated capital program and pursuing additional investment opportunities within existing service territories. Fortis has also demonstrated its ability to acquire additional regulated utilities in Canada and the United States. The Corporation's standalone operating model and financial strength, driven by a strong balance sheet and investment-grade credit ratings, positions it well for future investment opportunities in existing and new franchise areas.

KEY TRENDS, RISKS AND OPPORTUNITIES

Pending Acquisition of ITC Holdings Corp.: On February 9, 2016, Fortis and ITC Holdings Corp. ("ITC") (NYSE:ITC) entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction (the "Acquisition") 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. For details on the Acquisition, including transaction details, strategic rationale and acquisition financing, refer to the "Subsequent Event" section of this MD&A, and for a discussion of risks associated with the Acquisition, refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" section of this MD&A.

Electric Utility Industry Developments: The North American electric utility industry has changed significantly over the past several years. The most notable changes include a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. At the same time, the continued low interest rate environment and decrease in world oil and gas prices are having significant impacts on the North American economy. Notwithstanding the changes occurring in the utility industry, safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of the utility industry's focus.

Government and regulatory policy in Canada and the United States is being directed at environmental protection and energy efficiency. The increasing availability of cleaner sources of power generation are driving new environmental regulation designed to eliminate or reduce dependence on traditional sources of electricity power generation, such as coal. The availability of cheaper, cleaner burning natural gas, as well as growing accessibility of renewable or alternative energy sources like solar are encouraging governments to deploy aggressive targets for the removal of high carbon emission sources of energy. Reaching these targets will require the shutdown of certain high carbon emission generating plants earlier than planned, which is an issue that utilities and regulators need to address. These environmental regulations are, however, expected to create additional investment opportunities in renewable power generation and related energy infrastructure. Fortis' regulated utilities are actively involved in pursuing these opportunities.

Technological development, particularly in the area of distributed generation, is playing a significant role in the transformation of the utility industry. Although distributed generation customers remain connected to the electrical system and benefit from that connection, they avoid paying much of the fixed operating and maintenance costs because they can offset a portion of their volumetric energy usage with their own systems. This results in an increasing amount of utility costs that are ultimately shifted to other customers. The declining cost of certain types of distributed generation technologies, together with government subsidization, is encouraging increased adoption by customers. Not only does this expose the utility to declining revenue because of a decrease in energy sales, the rate structure serves to shift an increasing burden for these costs on those customers that do not have distributed generation, such as rooftop solar. Traditional rate designs have not been structured to ensure fairness among all customers, which is a focus for utilities and regulators. Fortis, through its subsidiaries, is working with its regulators to address these rate design issues for its customers.

Despite the challenges facing the utility industry, Fortis is well positioned to meet these headwinds and capitalize on any resulting opportunities. Its decentralized structure and customer focused business culture will support the efforts required to both meet evolving customer expectations and to work with policy makers and regulators on solutions that are financially sustainable for the utilities. Leveraging those relationships to get out in front of these evolving challenges will be essential to meeting the industry challenges.

Natural Gas Opportunities: FortisBC Energy continues to pursue opportunities in British Columbia related to gas infrastructure. The combination of an abundant supply of natural gas, low costs for natural gas and supportive government policy are generating new interest for large industrial customers and niche liquefied natural gas ("LNG") producers to utilize FortisBC Energy's gas system.

In 2013 the Government of British Columbia issued an Order in Council announcing the exemption of FEI's Tilbury LNG facility expansion ("Tilbury Expansion") from regulatory review. The Tilbury Expansion is well underway and will increase LNG production and storage capabilities, and is expected to be in service around the end of 2016. Since this announcement, there has been considerable interest for LNG supply from the Pacific Northwest, Hawaii, Alaska and international markets. In 2014 the Government of British Columbia issued a second Order in Council amending directions to the regulator regarding the Tilbury Expansion. The revisions set out a number of requirements for the regulator, including the consideration of a further expansion of the Tilbury site that would include additional liquefaction.

Traditionally, the majority of natural gas production in northern British Columbia has served the provincial and Pacific Northwest markets via the Westcoast (Spectra) system. However, to realize the full potential of British Columbia shale gas opportunities, additional capacity to connect to markets will have to be developed. FortisBC Energy continues to explore pipeline investment opportunities that include expansion of their existing distribution system to supply natural gas to a prospective LNG export facility, as well as to expand capacity on their Southern Crossing transmission pipeline. Specifically, FortisBC Energy is pursuing a potential pipeline expansion to the proposed Woodfibre LNG site in British Columbia. The Woodfibre LNG site is a former paper mill site located near Squamish, British Columbia. The Company has an opportunity to expand its gas pipeline and increase compression to deliver natural gas to this site.

For further information on the Corporation's natural gas investment opportunities, refer to the "Liquidity and Capital Resources – Additional Investment Opportunities" section of this MD&A.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's nine utilities is subject to regulation by the regulatory body in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level.

Commitment by the Corporation's utilities to provide safe and reliable service, operational excellence and promote positive customer and regulatory relations is important to ensure supportive regulatory relationships and obtain full cost recovery and competitive returns for the Corporation's shareholders.

Central Hudson began operating under a new three-year rate order in mid-2015. In November 2015 TEP filed a general rate application ("GRA") with the Arizona Corporation Commission ("ACC") requesting new retail rates to be effective January 1, 2017, using the year ended June 30, 2015 as a historical test year. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US$0.6 billion and the common equity component of capital structure increased from 43.5% to approximately 50%. The application also addresses rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service. In May 2015 UNS Electric filed a similar GRA requesting new retail rates effective May 1, 2016, using 2014 as a historical test year. The nature of UNS Electric's application was similar to that of TEP.

The Corporation's regulatory calendar for its utilities in Canada continues to be extensive. Newfoundland Power recently filed a GRA for 2016 and FortisBC Energy, the benchmark utility in British Columbia, filed its application to review cost of capital for 2016. In Alberta, while the regulator issued decisions on outstanding generic cost of capital proceedings and capital tracker applications early in 2015, it has initiated a generic cost of capital proceeding for 2016 and 2017, which includes FortisAlberta.

For a further discussion of the nature of regulation and material regulatory decisions and applications and regulatory risk, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth: The Corporation's regulated midyear rate base for 2015 was $16.4 billion. Over the five-year period through 2020, excluding the pending acquisition of ITC, the Corporation's 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%. Fortis expects this capital investment to support growth in earnings and dividends.

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

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities usually issue debt at terms ranging between 5 and 40 years. As at December 31, 2015, almost 90% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately $260 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $3.6 billion in credit facilities, of which approximately $2.4 billion was unused as at December 31, 2015. Based on current credit ratings and conservative capital structures, the Corporation and its regulated utilities expect to continue to have reasonable access to long-term capital in 2016.

The Corporation has significant financing requirements associated with the pending acquisition of ITC. Refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" and "Subsequent Event" sections of this MD&A.

Dividend Increases: Dividends paid per common share increased to $1.40 in 2015. During 2015 Fortis increased its quarterly dividend per common share over 17% to $0.375 per quarter, or $1.50 on an annualized basis. This continues the Corporation's record of raising its annualized dividend to common shareholders for 42 consecutive years, the record for a public corporation in Canada.

Fortis also announced dividend guidance, targeting annual dividend per common share growth through 2020 of 6% based on a 2016 dividend of $1.50. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its $9 billion 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.

SIGNIFICANT ITEMS IN 2015

Pending Acquisition of Aitken Creek Gas Storage Facility: In December 2015 Fortis, 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 ("Aitken Creek") for approximately US$266 million, subject to customary closing conditions and adjustments. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada's natural gas transmission network. The acquisition is subject to regulatory approval and is expected to close in the first half of 2016. The net cash purchase price is expected to be initially financed with borrowings under the Corporation's credit facility. In December 2015 the Corporation paid a deposit of US$29 million related to the transaction.

Sale of Commercial Real Estate and Hotel Assets: In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately $109 million, net of expenses. As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering.

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As a result of the sale, the Corporation recognized an after-tax loss of approximately $8 million, which reflects an impairment loss and expenses associated with the sale transaction.

Net proceeds from the sales were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy.

Sale of Non-Regulated Generation Assets in New York and Ontario: In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized an after-tax gain of approximately $27 million (US$22 million), net of expenses and foreign exchange impacts.

In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of approximately $16 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately $5 million.

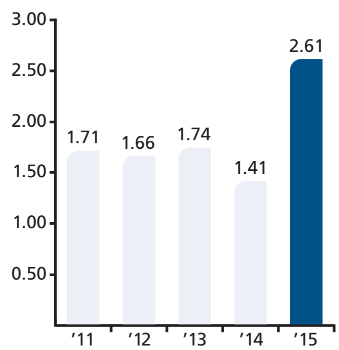
Settlement of Belize Electricity Expropriation Matters: In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate $9 million loss.

SUMMARY FINANCIAL HIGHLIGHTS

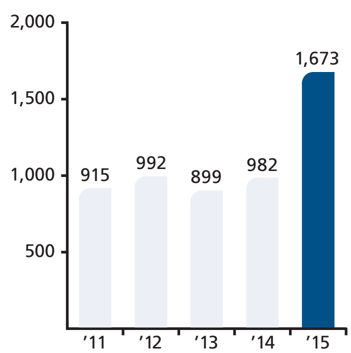
For the Years Ended December 31	2015	2014	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**728**	317	411
Basic Earnings per Common Share *($)*	**2.61**	1.41	1.20
Diluted Earnings per Common Share *($)*	**2.59**	1.40	1.19
Weighted Average Number of Common Shares Outstanding *(millions)*	**278.6**	225.6	53.0
Cash Flow from Operating Activities *($ millions)*	**1,673**	982	691
Dividends Paid per Common Share *($)*	**1.40**	1.28	0.12
Dividend Payout Ratio *(%)*	**53.6**	90.8	(37.2)
Return on Average Book Common Shareholders' Equity *(%)* [(1)]	**9.8**	5.4	4.4
Total Assets *($ billions)*	**28.8**	26.2	2.6
Gross Capital Expenditures *($ billions)*	**2.2**	1.7	0.5
Public Preference Share Offering *($ billions)*	**–**	0.6	(0.6)
Convertible Debenture Offering *($ billions)*	**–**	1.8	(1.8)
Long-Term Debt Offerings *($ billions)*	**1.0**	1.2	(0.2)

[(1)] Return on average book common shareholders' equity is a non-US GAAP measure and is defined as net earnings attributable to common equity shareholders divided by the average of opening and closing consolidated shareholders' equity, excluding preference shares and non-controlling interests. Return on average book common shareholders' equity is referred to by users of the Corporation's consolidated financial statements in evaluating the results of operations.

Basic Earnings per Common Share *($)*



Cash Flow from Operating Activities *($ millions)*



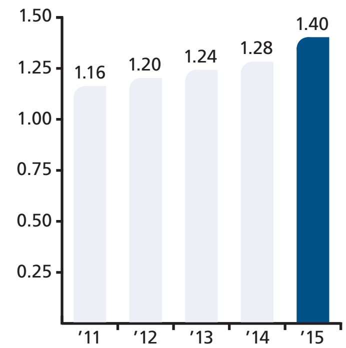
Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $728 million in 2015 compared to $317 million in 2014. On an adjusted basis, net earnings attributable to common equity shareholders for 2015 were $589 million, an increase of $195 million, or almost 50%, over 2014. Results for both years were impacted by non-recurring or adjusting items, which are detailed in the "Consolidated Results of Operations" section of this MD&A. The increase in adjusted net earnings attributable to common equity shareholders was driven by a full year's contribution from UNS Energy, which was acquired in mid-August 2014, earnings contribution from the Waneta Expansion, which came online in early April 2015, rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta, a higher allowance for funds used during construction ("AFUDC") at FortisBC Energy, the resetting of customer rates at Central Hudson, effective July 1, 2015, and the continued strength of the US dollar relative to the Canadian dollar. Earnings growth was tempered by an increase in Corporate expenses and lower earnings contribution due to the sale of the commercial real estate and hotel assets.

Basic Earnings per Common Share: Basic earnings per common share were $2.61 in 2015 compared to $1.41 in 2014. On an adjusted basis, as noted above, basic earnings per common share were $2.11 for 2015, an increase of $0.36 over 2014. The increase was driven by higher adjusted earnings per common share, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding.

Cash Flow from Operating Activities: Cash flow from operating activities was $1,673 million for 2015, an increase of $691 million, or 70%, over 2014. The increase was driven by higher cash earnings, mainly due to the factors noted above, and favourable changes in working capital.

Dividends: Dividends paid per common share increased to $1.40 in 2015, 9.0% higher than $1.28 in 2014. During 2015 Fortis increased its quarterly dividend per common share over 17% to $0.375 per quarter. The Corporation's dividend payout ratio was 53.6% in 2015 compared to 90.8% in 2014. On an adjusted basis, the dividend payout ratio was 66.4% in 2015 compared to 73.1% in 2014.

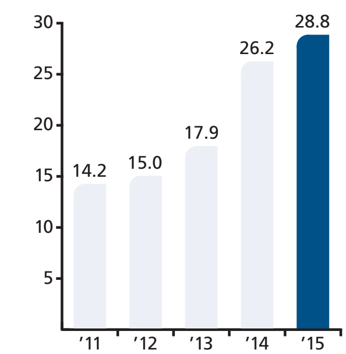
Dividends Paid per Common Share *($)*



Return on Average Book Common Shareholders' Equity: The return on average book common shareholders' equity for 2015 was 9.8% compared to 5.4% for 2014. On an adjusted basis, the return on average book common shareholders' equity for 2015 was 7.9%, compared to 6.8% for 2014.

Total Assets: Total assets increased 9.9% to approximately $28.8 billion at the end of 2015 compared to approximately $26.2 billion at the end of 2014. The increase reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets in 2015.

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



Gross Capital Expenditures: Consolidated capital expenditures, before customer contributions, were $2.2 billion in 2015 compared to $1.7 billion in 2014. The increase was driven by a full year contribution from UNS Energy and higher capital spending at most of the Corporation's regulated utilities, partially offset by lower non-regulated capital expenditures due to the completion of the Waneta Expansion and the sale of commercial real estate and hotel assets. For a detailed discussion of the Corporation's consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Long-Term Capital: The Corporation's regulated utilities raised approximately $1 billion in long-term debt in 2015, largely in support of energy infrastructure investment and regularly scheduled debt repayments.

Fortis completed the sale of $1.8 billion convertible debentures in 2014 to finance a portion of the acquisition of UNS Energy. In October 2014 approximately 58.2 million common shares of Fortis were issued on conversion of the debentures. In September 2014 Fortis issued 24 million First Preference Shares, Series M for gross proceeds of $600 million. The net proceeds were also used to finance a portion of the acquisition of UNS Energy. The Corporation and its regulated utilities raised approximately $1.2 billion in long-term debt in 2014.

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

CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31

($ millions)	**2015**	2014	Variance
Revenue	**6,727**	5,401	1,326
Energy Supply Costs	**2,561**	2,197	364
Operating Expenses	**1,864**	1,493	371
Depreciation and Amortization	**873**	688	185
Other Income (Expenses), Net	**187**	(25)	212
Finance Charges	**553**	547	6
Income Tax Expense	**223**	66	157
Earnings From Continuing Operations	**840**	385	455
Earnings From Discontinued Operations, Net of Tax	**–**	5	(5)
Net Earnings	**840**	390	450
Net Earnings Attributable to:			
Non-Controlling Interests	**35**	11	24
Preference Equity Shareholders	**77**	62	15
Common Equity Shareholders	**728**	317	411
Net Earnings	**840**	390	450

Revenue

The increase in revenue was driven by the acquisition of UNS Energy in August 2014. Favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion and higher base electricity rates at the Canadian Regulated Electric Utilities also contributed to the increase. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

Energy Supply Costs

The increase in energy supply costs was primarily due to the acquisition of UNS Energy and unfavourable foreign exchange associated with the translation of US dollar-denominated energy supply costs. The increase was partially offset by lower commodity costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities.

Operating Expenses

The increase in operating expenses was primarily due to the acquisition of UNS Energy, unfavourable foreign exchange associated with the translation of US dollar-denominated operating expenses and general inflationary and employee-related cost increases. The increase was partially offset by a decrease in non-utility operating expenses due to the sale of commercial real estate and hotel assets, and lower Corporate retirement expenses.

Depreciation and Amortization

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

Other Income (Expenses), Net

The increase in other income, net of expenses, was driven by gains on the sale of commercial real estate and non-regulated generation assets in 2015, compared to acquisition-related expenses associated with UNS Energy in 2014. The increase was partially offset by a loss associated with the sale of hotel assets in 2015.

Finance Charges

The increase in finance charges was primarily due to the acquisition of UNS Energy, including interest expense on debt issued to complete the financing of the acquisition, and unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense. The increase was partially offset by lower interest on convertible debentures. Approximately $72 million ($51 million after tax) in interest expense was recognized in 2014 associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy. In October 2014 the convertible debentures were substantially all converted into common shares of the Corporation.

Income Tax Expense

The increase in income tax expense was primarily due to higher earnings before income taxes, driven by the acquisition of UNS Energy and gains on the sale of commercial real estate and non-regulated generation assets in 2015, and a higher effective income tax rate, mainly due to the combined federal and state income tax rate at UNS Energy.

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

Net earnings attributable to common equity shareholders were impacted by a number of non-recurring or non-operating items. These items, referred to as adjusting items, are reconciled below and discussed in the segmented results of operations for the respective reporting segments. Management believes that adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share provide useful information to investors and shareholders as they provide increased transparency and predictive value. The adjusting items do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. Therefore, these adjusting items may not be comparable with similar measures presented by other companies.

Non-US GAAP Reconciliation

Years Ended December 31 *($ millions, except for common share data)*	**2015**	2014	Variance
Net Earnings Attributable to Common Equity Shareholders	**728**	317	411
Adjusting Items:			
FortisAlberta –			
Capital tracker revenue adjustment for 2013 and 2014	**(9)**	–	(9)
Non-Regulated – Fortis Generation –			
Gain on sale of generation assets	**(32)**	–	(32)
Non-Utility –			
Gain on sale of commercial real estate assets	**(109)**	–	(109)
Loss on sale of hotel assets	**8**	–	8
Earnings from discontinued operations	**–**	(5)	5
Corporate and Other –			
Foreign exchange gain	**(13)**	(8)	(5)
Loss on settlement of expropriation matters	**9**	–	9
Interest expense on convertible debentures	**–**	51	(51)
Acquisition-related expenses	**7**	39	(32)
Adjusted Net Earnings Attributable to Common Equity Shareholders	**589**	394	195
Adjusted Basic Earnings Per Common Share *($)*	**2.11**	1.75	0.36

Adjusted Net Earnings Attributable to Common Equity Shareholders

The increase in adjusted net earnings attributable to common equity shareholders was driven by earnings contribution of $195 million at UNS Energy compared to $60 million for 2014. Earnings contribution of $22 million from the Waneta Expansion, which represents the Corporation's 51% controlling ownership interest, also contributed to the increase. Performance was driven by all of the Corporation's other regulated utilities, including rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta; a higher AFUDC at FortisBC Energy; and improved performance at Central Hudson under a new three-year rate order. Favourable foreign exchange impacts associated with US dollar-denominated earnings also increased earnings year over year. The increase in adjusted earnings was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy, and lower earnings contribution from non-utility assets due to the sale of commercial real estate and hotel assets.

Adjusted Basic Earnings Per Common Share

The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of UNS Energy, after considering the finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding, and contribution from the Waneta Expansion. Performance at all of the Corporation's other regulated utilities, as discussed above, and the impact of favourable foreign exchange also contributed to the increase. The increase was partially offset by an increase in Corporate expenses and lower earnings contribution from non-utility assets due to the sale of commercial real estate and hotel assets.

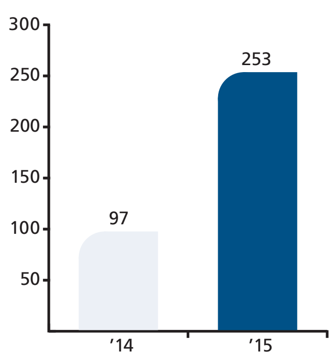
SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

Years Ended December 31 *($ millions)*	2015	2014	Variance
Regulated Electric & Gas Utilities – United States			
UNS Energy	**195**	60	135
Central Hudson	**58**	37	21
	253	97	156
Regulated Gas Utility – Canadian			
FortisBC Energy	**140**	127	13
Regulated Electric Utilities – Canadian			
FortisAlberta	**138**	103	35
FortisBC Electric	**50**	46	4
Eastern Canadian	**62**	60	2
	250	209	41
Regulated Electric Utilities – Caribbean	**34**	27	7
Non-Regulated – Fortis Generation	**77**	20	57
Non-Regulated – Non-Utility	**114**	28	86
Corporate and Other	**(140)**	(191)	51
Net Earnings Attributable to Common Equity Shareholders	**728**	317	411

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

Regulated Electric & Gas Utilities – United States Earnings *($ millions)*



REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2015 earnings from regulated assets represented approximately 92% (2014 – 91%) of the Corporation's earnings from its operating segments (excluding Corporate and Other segment expenses), excluding the gains on sale of non-core assets. Total regulated assets represented 96% of the Corporation's total assets as at December 31, 2015 (December 31, 2014 – 93%).

Regulated Electric & Gas Utilities – United States

Regulated Electric & Gas Utilities – United States earnings for 2015 were $253 million (2014 – $97 million), which represented approximately 37% (2014 – 21%) of the Corporation's total regulated earnings. Total segment assets were approximately $12.1 billion as at December 31, 2015 (December 31, 2014 – $9.9 billion), which represented approximately 44% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 40%).

UNS Energy

Financial Highlights [(1)]

Years Ended December 31	2015	2014
Average US:CAD Exchange Rate [(2)]	**1.28**	1.12
Electricity Sales *(gigawatt hours ("GWh"))*	**15,366**	5,646
Gas Volumes *(petajoules ("PJ"))*	**13**	5
Revenue *($ millions)*	**2,034**	684
Earnings *($ millions)*	**195**	60

[(1)] Financial results of UNS Energy are from August 15, 2014, the date of acquisition.

[(2)] The reporting currency of UNS Energy is the US dollar. The average US:CAD exchange rate for 2014 is from the date of acquisition.

Electricity Sales & Gas Volumes

Electricity sales were 15,366 gigawatt hours ("GWh") for 2015 compared to 14,560 GWh for the full year in 2014. The increase was primarily due to higher short-term wholesale electricity sales. The majority of short-term wholesale electricity sales is flowed through to customers and has no impact on earnings. Retail sales were comparable year over year.

Gas volumes of 13 petajoules ("PJ") for 2015 were comparable with the full year in 2014.

Revenue

Revenue was US$1,588 million for 2015 compared to US$1,560 million for the full year in 2014. The increase was primarily due to the flow through to customers of higher purchased power and fuel supply costs, higher transmission revenue, and higher wholesale electricity sales. On a Canadian dollar basis, revenue was also impacted by favourable foreign exchange.

Earnings

Earnings were US$152 million for 2015 compared to US$144 million for the full year in 2014, excluding the impact of acquisition-related expenses. The increase was primarily due to higher transmission revenue and a decrease in interest expense due to the expiry of leasing arrangements. The increase was partially offset by higher operating expenses. On a Canadian dollar basis, earnings were also impacted by favourable foreign exchange.

Central Hudson

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Average US:CAD Exchange Rate [(1)]	**1.28**	1.10	0.18
Electricity Sales *(GWh)*	**5,132**	5,075	57
Gas Volumes *(PJ)*	**24**	23	1
Revenue *($ millions)*	**880**	821	59
Earnings *($ millions)*	**58**	37	21

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

Electricity Sales & Gas Volumes

The increase in electricity sales was mainly due to higher average consumption as a result of warmer temperatures in the summer, which increased the use of air conditioning and other cooling equipment. Gas volumes for 2015 were comparable with last year.

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

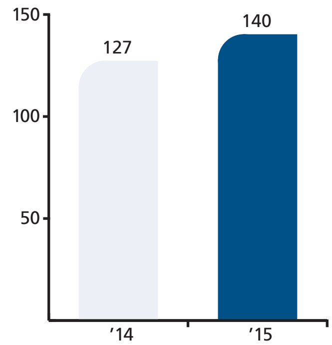
Revenue

The increase in revenue was driven by approximately $111 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue. An increase in base electricity rates effective July 1, 2015 and the recovery from customers of previously deferred electricity costs also contributed to the increase in revenue. Additionally, revenue for the first half of 2015 was favourably impacted by energy efficiency incentives and higher gas revenue associated with a new gas delivery contract in late 2014. The increase was partially offset by the recovery from customers of lower commodity costs, which were mainly due to lower wholesale prices.

Earnings

The increase in earnings was primarily due to approximately $9 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, an increase in base electricity rates effective July 1, 2015, a new gas delivery contract implemented in late 2014, and energy efficiency incentives earned during the first half of 2015. The increase was partially offset by the impact of higher expenses during the two-year rate freeze period post acquisition, which ended on June 30, 2015.

Regulated Gas Utility – Canadian Earnings *($ millions)*



Regulated Gas Utility – Canadian

Regulated Gas Utility – Canadian earnings for 2015 were $140 million (2014 – $127 million), which represented approximately 21% of the Corporation's total regulated earnings (2014 – 28%). Total segment assets were approximately $6.0 billion as at December 31, 2015 (December 31, 2014 – $5.8 billion), which represented approximately 22% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 24%).

FortisBC Energy

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Gas Volumes *(PJ)*	**186**	195	(9)
Revenue *($ millions)*	**1,295**	1,435	(140)
Earnings *($ millions)*	**140**	127	13

Gas Volumes

The decrease in gas volumes was primarily due to lower average consumption in the first quarter as a result of warmer temperatures.

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

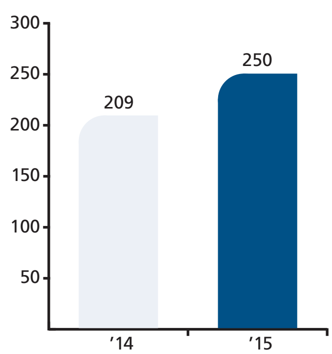
Revenue

The decrease in revenue was primarily due to a lower commodity cost of natural gas charged to customers and lower gas volumes. The decrease was partially offset by higher regulatory flow-through deferral amounts.

Earnings

The increase in earnings was mainly due to higher AFUDC, regulatory flow-through deferral amounts and operating cost savings, net of the earnings sharing mechanism. The increase was partially offset by a decrease in the allowed ROE and equity component of capital structure as a result of the amalgamation of FEVI and FEWI with FEI, effective December 31, 2014. For further details on the amalgamation, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Regulated Electric Utilities – Canadian Earnings *($ millions)*



Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2015 were $250 million (2014 – $209 million), which represented approximately 37% of the Corporation's total regulated earnings (2014 – 45%). Total segment assets were approximately $8.2 billion as at December 31, 2015 (December 31, 2014 – $7.7 billion), which represented approximately 30% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 32%).

FortisAlberta

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Energy Deliveries *(GWh)*	**17,132**	17,372	(240)
Revenue *($ millions)*	**563**	518	45
Earnings *($ millions)*	**138**	103	35

Energy Deliveries

The decrease in energy deliveries was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas, partially offset by higher average consumption by farm and irrigation, residential and commercial customers. Lower levels of precipitation, particularly in the third quarter, and warmer temperatures had a favorable impact on energy deliveries to farm and irrigation customers. Higher energy deliveries to residential and commercial customers due to customer growth were partially offset by lower average consumption due to warmer temperatures.

Revenue

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 increase in revenue was primarily due to the operation of the PBR formula, including an increase in customer rates based on a combined inflation and productivity factor of 1.49%, higher capital tracker revenue, growth in the number of customers, and higher revenue related to flow-through costs to customers. Revenue was also favourably impacted by a $9 million capital tracker revenue adjustment recognized in 2015 associated with 2013 and 2014, as a result of regulatory decisions. For further details on regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Earnings

The increase in earnings was primarily due to rate base growth associated with capital expenditures, growth in the number of customers, and the impact of a technical update on depreciation and amortization. Also contributing to the increase in earnings was capital tracker revenue of approximately $9 million recognized in 2015 associated with 2013 and 2014, as discussed above.

FortisBC Electric

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Electricity Sales *(GWh)*	**3,116**	3,179	(63)
Revenue *($ millions)*	**360**	334	26
Earnings *($ millions)*	**50**	46	4

Electricity Sales

The decrease in electricity sales was primarily due to lower average consumption in the first and fourth quarters as a result of warmer temperatures.

Revenue

The increase in revenue was driven by increases in base electricity rates, mainly established to recover higher power purchase costs, and surplus capacity sales. Revenue was also favourably impacted by higher contribution from non-regulated operating, maintenance and management services associated with the Waneta Expansion. The increase was partially offset by lower electricity sales.

Earnings

The increase in earnings was primarily due to higher earnings from non-regulated operating, maintenance and management services, and rate base growth.

Eastern Canadian Electric Utilities

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Electricity Sales *(GWh)*	**8,403**	8,376	27
Revenue *($ millions)*	**1,033**	1,008	25
Earnings *($ millions)*	**62**	60	2

Electricity Sales

The increase in electricity sales was primarily due to customer growth in Newfoundland, as well as higher average consumption in PEI, mainly due to an increase in the number of customers using electricity for home heating. The increase was partially offset by lower electricity sales in Ontario, largely due to the loss of a commercial customer and lower average consumption by residential customers due to changes in temperatures.

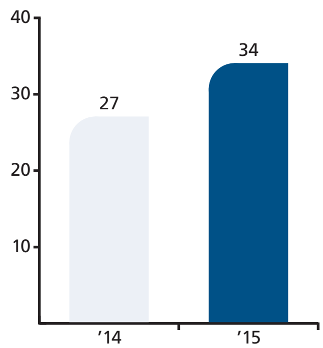
Revenue

The increase in revenue was mainly due to the flow through in customer electricity rates of overall higher energy supply costs and electricity sales growth.

Earnings

The increase in earnings was primarily due to electricity sales growth and lower operating costs, mainly due to restoration efforts at Newfoundland Power following the loss of energy supply from Newfoundland and Labrador Hydro ("Newfoundland Hydro") and related power interruptions in January 2014, partially offset by higher depreciation expense.

Regulated Electric Utilities – Caribbean Earnings *($ millions)*



Regulated Electric Utilities – Caribbean

Regulated Electric Utilities – Caribbean earnings for 2015 were $34 million (2014 – $27 million), which represented approximately 5% of the Corporation's total regulated earnings (2014 – 6%). Total segment assets were approximately $1.3 billion as at December 31, 2015 (December 31, 2014 – $1.1 billion), which represented approximately 4% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 4%).

Financial Highlights

Years Ended December 31	2015	2014	Variance
Average US:CAD Exchange Rate [(1)]	**1.28**	1.10	0.18
Electricity Sales *(GWh)*	**802**	771	31
Revenue *($ millions)*	**321**	321	–
Earnings *($ millions)*	**34**	27	7

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

Electricity Sales

The increase in electricity sales was primarily due to growth in the number of customers as a result of increased economic activity and overall warmer temperatures, which increased air conditioning load.

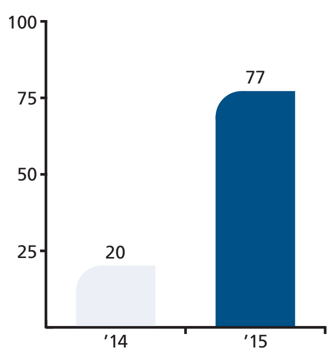
Revenue

Revenue was impacted by approximately $39 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, and electricity sales growth. The increase was largely offset by the flow through in customer electricity rates of lower fuel costs at Caribbean Utilities.

Earnings

The increase in earnings was due to approximately $5 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, electricity sales growth and higher capitalized interest at Caribbean Utilities. The increase was partially offset by higher depreciation. Equity income from Belize Electricity from the date of settlement in August 2015 was less than $1 million.

Non-Regulated – Fortis Generation Earnings *($ millions)*



NON-REGULATED

Non-Regulated – Fortis Generation

Financial Highlights

Years Ended December 31	2015	2014	Variance
Energy Sales *(GWh)*	**844**	407	437
Revenue *($ millions)*	**107**	38	69
Earnings *($ millions)*	**77**	20	57

Energy Sales

The increase in energy sales was driven by the Waneta Expansion, which commenced production in early April 2015 and reported energy sales of 517 GWh in 2015. The increase was partially offset by decreased production in Belize due to lower rainfall and in Upstate New York and Ontario due to the sale of generation assets in mid 2015, lower rainfall, and generating units taken out of service for repairs.

Revenue

The increase in revenue was driven by the Waneta Expansion, which recognized revenue of $70 million in 2015, and approximately $4 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue. The increase was partially offset by decreased production in Belize, Upstate New York and Ontario.

Earnings

The increase in earnings was driven by the recognition of after-tax gains totalling approximately $32 million on the sale of generation assets in Upstate New York and Ontario in mid 2015, and earnings contribution of $22 million from the Waneta Expansion. Approximately $3 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings and lower business development costs were partially offset by decreased production in Belize, Upstate New York and Ontario.

Non-Regulated – Non-Utility

Financial Highlights

Years Ended December 31 ($ millions)	2015	2014	Variance
Revenue	**171**	249	(78)
Earnings	**114**	28	86

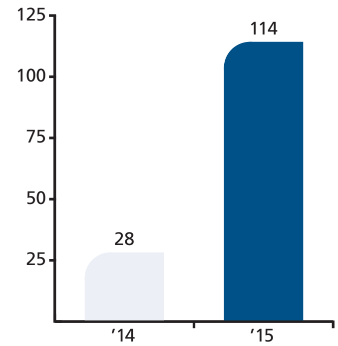
Revenue

The decrease in revenue was primarily due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

Earnings

The increase in earnings was driven by a net after-tax gain of approximately $101 million on the sale of commercial real estate and hotel assets. The increase was partially offset by lower earnings contribution from the commercial real estate and hotel assets as a result of the sale and $5 million in earnings in 2014 associated with Griffith from normal operations to the date of sale in March 2014.

Non-Regulated – Non-Utility Earnings
($ millions)



Corporate and Other

Financial Highlights

Years Ended December 31 ($ millions)	2015	2014	Variance
Revenue	**24**	31	(7)
Operating Expenses	**26**	38	(12)
Depreciation and Amortization	**2**	2	–
Other Income (Expenses), Net	**(8)**	(45)	37
Finance Charges	**94**	154	(60)
Income Tax Recovery	**(43)**	(79)	36
	(63)	(129)	66
Preference Share Dividends	**77**	62	15
Net Corporate and Other Expenses	**(140)**	(191)	51

Net Corporate and Other expenses were impacted by the following items.

(i) A foreign exchange gain of $13 million in 2015 compared to $8 million in 2014, associated with the Corporation's previous US-dollar denominated long-term other asset that represented the book value of its expropriated investment in Belize Electricity, which was included in other income;
(ii) A loss of approximately $9 million in 2015 on settlement of expropriation matters related to the Corporation's investment in Belize Electricity, which was included in other income, net of expenses;
(iii) Acquisition-related expenses of $10 million ($7 million after tax) in 2015 associated with the pending acquisition of ITC, which were included in other income;
(iv) Finance charges of $72 million ($51 million after tax) in 2014 associated with the convertible debentures issued to finance a portion of the acquisition of UNS Energy; and
(v) Other expenses of approximately $58 million ($39 million after tax) in 2014 related to the acquisition of UNS Energy.

Excluding the above-noted items, net Corporate and Other expenses were $137 million for 2015 compared to approximately $109 million for 2014. The increase in net Corporate and Other expenses was primarily due to higher preference share dividends and finance charges, and a decrease in revenue. The increase was partially offset by lower operating expenses.

The increase in preference share dividends and finance charges was primarily due to the acquisition of UNS Energy. Finance charges were also impacted by no longer capitalizing interest upon completion of the Waneta Expansion and unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense.

The decrease in revenue was primarily due to a decrease in related-party interest income, mainly due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

The decrease in operating expenses was primarily due to lower retirement expenses. Retirement expenses of approximately $13 million ($11 million after tax) were recognized in 2014 compared to approximately $2 million ($1 million after tax) in 2015. The decrease in operating expenses was partially offset by a $3 million ($2 million after tax) corporate donation recognized in 2015.

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated electric and gas utilities are summarized as follows.

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2014	2015	2016	Significant Features / Future or Historical Test Year Used to Set Customer Rates
			ROE			
TEP	ACC	43.5	10.00	10.00	10.00	COS/ROE (1)
UNS Electric	ACC	52.6 (2)	9.50	9.50	9.50 (2)	ROEs established by the ACC
UNS Gas	ACC	50.8	9.75	9.75	9.75	Historical Test Year
Central Hudson	New York State Public Service Commission ("PSC")	48	10.00	10.00/ 9.00 (3)	9.00	COS/ROE Earnings sharing mechanism ROE established by the PSC Future Test Year
FEI	British Columbia Utilities Commission ("BCUC")	38.5 (2)	8.75	8.75	8.75 (2)	COS/ROE PBR mechanism for 2014 through 2019
FEVI	BCUC	41.5 (4)	9.25	n/a (4)	n/a (4)	ROEs established by the BCUC
FEWI	BCUC	41.5 (4)	9.50	n/a (4)	n/a (4)	2013 test year with 2014 through 2019 rates set using PBR mechanism
FortisBC Electric	BCUC	40 (2)	9.15	9.15	9.15 (2)	COS/ROE PBR mechanism for 2014 through 2019 ROE established by the BCUC 2013 test year with 2014 through 2019 rates set using PBR mechanism
FortisAlberta	Alberta Utilities Commission ("AUC")	40 (2)	8.30	8.30	8.30 (2)	COS/ROE PBR mechanism for 2013 through 2017 with capital tracker account and other supportive features ROE established by the AUC 2012 test year with 2013 through 2017 rates set using PBR mechanism
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45 (2)	8.80 +/– 50 bps	8.80 +/– 50 bps	8.80 (2) +/– 50 bps	COS/ROE ROE established by the PUB Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40 (2)	9.75	9.75	9.35 (2)	COS/ROE ROE established by the *PEI Energy Accord* in 2014 and 2015. ROE in 2016 to be established by IRAC Future Test Year
FortisOntario	Ontario Energy Board	40	8.93 – 9.85	8.93 – 9.30	8.93 – 9.30	COS/ROE (5) Future test year and incentive regulation rate-setting mechanism
			ROA			
Caribbean Utilities	Electricity Regulatory Authority	N/A	7.00 – 9.00	7.25 – 9.25	6.75 – 8.75	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Historical Test Year
Fortis Turks and Caicos	Government of the Turks and Caicos Islands	N/A	15.00 – 17.50 (6)	15.00 – 17.50 (6)	15.00 – 17.50 (6)	COS/ROA Historical Test Year

(1) Additionally, allowed ROEs are adjusted for the fair value of rate base as required under the laws of the State of Arizona.
(2) Interim and subject to change pending the outcome of regulatory proceedings effective January 1, 2016 for FortisAlberta, FEI and FortisBC Electric; May 1, 2016 for UNS Electric; July 1, 2016 for Newfoundland Power; and March 1, 2016 for Maritime Electric.
(3) Allowed ROE of 10.0% with a 48% common equity component of capital structure to June 30, 2015. Allowed ROE of 9.00% with a 48% common equity component of capital structure effective July 1, 2015 through June 30, 2018.
(4) As approved by the BCUC, effective December 31, 2014, FEVI and FEWI were amalgamated with FEI and, as a result, the allowed ROE and common equity component of capital structure for 2015 reverted to those of FEI.
(5) Cornwall Electric is subject to a rate-setting mechanism under a Franchise Agreement with the City of Cornwall, based on a price cap with commodity cost flow through.
(6) Achieved ROAs at the utilities are significantly lower than those allowed under licences as a result of the inability, due to economic and political factors, to increase base customer electricity rates.

Material Regulatory Decisions and Applications

The following summarizes the significant regulatory decisions and applications for the Corporation's regulated utilities for 2015.

UNS Energy

In November 2015 TEP, UNS Energy's largest utility, filed a GRA with the ACC requesting new retail rates to be effective January 1, 2017, using the year ended June 30, 2015 as a historical test year. The key provisions of the rate request include: (i) a base retail rate increase of US$110 million, or 12.0%, compared with adjusted test year revenue; (ii) a 7.34% return on original cost rate base of US$2.1 billion; (iii) a common equity component of capital structure of approximately 50%; (iv) a cost of equity of 10.35% and an average cost of debt of 4.32%; and (v) rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US$0.6 billion and the common equity component of capital structure increased from 43.5% to approximately 50%. In May 2015 UNS Electric filed a GRA requesting new retail rates to be effective May 1, 2016, using 2014 as a historical test year. The nature of UNS Electric's GRA was similar to that of TEP. A decision on UNS Electric's application is expected in the third quarter of 2016 and TEP's application is expected in the fourth quarter of 2016.

Central Hudson

Three-Year Rate Order

In June 2015 the PSC issued a Rate Order for Central Hudson covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. A delivery rate freeze was implemented for electricity and natural gas delivery rates through June 30, 2015 as part of the regulatory approval of the acquisition of Central Hudson by Fortis. Central Hudson invested approximately US$225 million in energy infrastructure during the two-year delivery rate freeze period ended June 30, 2015. The approved Rate Order reflects an allowed ROE of 9.0% and a 48% common equity component of capital structure. The Rate Order includes capital investments of approximately US$490 million during the three-year period targeted at making the electric and gas systems stronger.

The approved Rate Order includes full cost recovery of electric and natural gas commodity costs and continuation of certain mechanisms, including revenue decoupling and earnings sharing mechanisms. In the approved earnings sharing mechanism, the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer. In addition, the Rate Order includes a major storm reserve for electric operations and provides for continuation of recovery of various operating expenses, including environmental site investigation and remediation costs. To the extent that Central Hudson receives gas delivery revenue associated with a new contract implemented in late 2014, associated revenue is being used to mitigate future gas customer rate increases, effective July 1, 2015.

Reforming the Energy Vision

In 2014 the PSC issued an order instituting a proceeding to reform New York State's electricity industry and regulatory practices ("Reforming the Energy Vision"). The initiative seeks to further a number of policy objectives and seeks to determine the appropriate role of electric distribution utilities in furthering these objectives, as well as considering regulatory changes to better align utility interest with energy policy objectives. In 2015 Central Hudson continued to fully participate in this proceeding. The outcome of Reforming the Energy Vision cannot be determined at this time and it could impact the scope of regulated utilities in New York State.

FortisBC Energy and FortisBC Electric

Multi-Year PBR Plans

In September 2014 the BCUC issued its decisions on FEI and FortisBC Electric's Multi-Year PBR Plans for 2014 through 2019. The approved PBR Plans incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FEI and 1.03% for FortisBC Electric each year. The approved PBR Plans also include a 50%/50% sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI and FortisBC Electric maintain service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between the utilities and interested parties regarding current performance and future activities.

In May 2015 and June 2015, the BCUC issued its decisions on FEI and FortisBC Electric's 2015 rates in compliance with the PBR decisions issued in September 2014. The decisions approved 2015 midyear rate base of approximately $3,661 million and $1,249 million for FEI and FortisBC Electric, respectively, and approved customer rate increases for 2015 of 0.7% and 4.2% over 2014 rates, respectively.

In December 2015 the BCUC issued its decisions on FEI and FortisBC Electric's 2016 rates. The decisions approved 2016 midyear rate base of approximately $3,693 million and $1,286 million for FEI and FortisBC Electric, respectively, and approved customer rate increases for 2016 of 1.79% and 2.96% over 2015 rates, respectively.

Generic Cost of Capital Proceedings

A Generic Cost of Capital ("GCOC") Proceeding to establish the allowed ROE and capital structures for regulated utilities in British Columbia occurred from 2012 through 2014. FEI was designated as the benchmark utility and a BCUC decision established that the ROE for the benchmark utility would be set at 8.75% with a 38.5% common equity component of capital structure, both effective January 1, 2013 through December 31, 2015. The GCOC Proceeding reaffirmed for FortisBC Electric a risk premium over the benchmark utility of 40 basis points, resulting in an allowed ROE of 9.15% effective January 1, 2013 through December 31, 2015, and a common equity component of capital structure at 40%.

The BCUC decision directed FEI to file an application to review the 2016 benchmark utility ROE and common equity component of capital structure. In October 2015, as required by the regulator, FEI filed its application to review the 2016 benchmark allowed ROE and common equity component of capital structure. As FEI is the benchmark utility, the review of the application could also have an impact on FortisBC Electric. A decision on the application is expected in the second quarter of 2016.

FortisAlberta

Generic Cost of Capital Proceedings

In March 2015 the AUC issued its decision on the GCOC Proceeding in Alberta. The GCOC Proceeding set FortisAlberta's allowed ROE for 2013 through 2015 at 8.30%, down from the interim allowed ROE of 8.75%, and set the common equity component of capital structure at 40%, down from 41%. The AUC also determined that it would not re-establish a formula-based approach to setting the allowed ROE at this time. Instead, the allowed ROE of 8.30% and common equity component of capital structure of 40% will remain in effect on an interim basis for 2016 and beyond. For regulated utilities in Alberta under PBR mechanisms, including FortisAlberta, the impact of the changes to the allowed ROE and common equity component of capital structure resulting from the GCOC Proceeding applies to the portion of rate base that is funded by capital tracker revenue only. For assets not being funded by capital tracker revenue, no revenue adjustment is required for the change in the allowed ROE and common equity component of capital structure, from that set in an earlier GCOC decision.

In April 2015 the AUC initiated a GCOC Proceeding to set the allowed ROE and capital structure for 2016 and 2017. While the AUC approved a request by utilities in Alberta to negotiate matters at issue in the GCOC Proceeding for 2016, a negotiated settlement was not reached and a 2016 and 2017 GCOC Proceeding commenced. A hearing is scheduled for June 2016 and a decision is expected before the end of 2016.

Capital Tracker Applications

The funding of capital expenditures during the PBR term is a material aspect of the PBR plan for FortisAlberta. The PBR plan provides a capital tracker mechanism to fund the recovery of costs associated with certain qualifying capital expenditures.

In March 2015 the AUC issued its decision related to FortisAlberta's 2013, 2014 and 2015 Capital Tracker Applications. The decision: (i) indicated that the majority of the Company's applied for capital trackers met the established criteria and were, therefore, approved for collection from customers; (ii) approved FortisAlberta's accounting test to determine qualifying K factor amounts; and (iii) confirmed certain inputs to be used in the accounting test, including the conclusion that the weighted average cost of capital be based on actual debt rates and the allowed ROE and capital structure approved in the GCOC Proceeding.

In September 2015 the AUC approved FortisAlberta's compliance filing related to the 2015 Capital Tracker Decision, substantially as filed. Capital tracker revenue of $17 million was approved for 2013 on an actual basis and capital tracker revenue of $42 million and $62 million was approved on a forecast basis for 2014 and 2015, respectively. FortisAlberta collected $15 million, $29 million and $62 million in 2013, 2014 and 2015, respectively, related to capital tracker expenditures.

In May 2015 FortisAlberta filed an application with the AUC seeking: (i) capital tracker revenue of $72 million for 2016 and $90 million for 2017; (ii) a reduction of $5 million to the 2014 capital tracker revenue to reflect actual capital expenditures; and (iii) approval of additional revenue related to capital tracker amounts that had not been fully approved in the 2015 Capital Tracker Decision. A hearing related to this proceeding concluded in October 2015, with a decision from the regulator expected in the first quarter of 2016.

FortisAlberta recognized capital tracker revenue of approximately $59 million in 2015, of which $9 million was related to updates to the 2013 and 2014 capital tracker approved amounts. The capital tracker revenue for 2015 of approximately $50 million incorporates an update for related 2015 capital expenditures as compared to the approved forecast reflected in current rates. This resulted in a deferral of $12 million of 2015 capital tracker revenue as a regulatory liability.

2016 Annual Rates Application

In December 2015 the regulator approved FortisAlberta's 2016 Annual Rates Application substantially as filed. The rates and riders, effective January 1, 2016, include an increase of approximately 4.6% to the distribution component of customer rates. This increase reflects: (i) a combined inflation and productivity factor of 0.9%; (ii) a K factor placeholder of $64 million, which is 90% of the depreciation and return associated with the 2016 forecast capital tracker expenditures as filed in the capital tracker applications, as discussed previously; and (iii) $17 million for adjustments to 2013, 2014 and 2015 capital tracker revenue as filed in the capital tracker compliance filing related to the 2015 capital tracker decision.

Utility Asset Disposition Matters

In previous decisions, the AUC made statements regarding cost responsibility for stranded assets and gains or losses related to extraordinary retirement of utility assets, which FortisAlberta and other Alberta utilities challenged as being incorrectly made. Stranded assets are generally understood to be utility assets no longer used to provide utility service as a result of extraordinary circumstances. The AUC's statements implied that the shareholder is responsible for the cost of stranded assets in a broader sense than that generally understood by regulated utilities and also conflicted with the *Electric Utilities Act* (Alberta). As a result, the utilities in Alberta had filed leave to appeal motions with the Court of Appeal of Alberta.

In September 2015 the Court of Appeal of Alberta issued a decision that dismissed the appeals of the utilities. The basis for the decision was that the AUC should be accorded deference for its conclusions in utility asset disposition matters. The decision by the Court of Appeal of Alberta has no immediate impact on FortisAlberta's financial position. However, the Company is exposed to the risk that unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to an extraordinary retirement will not be recoverable from customers. In November 2015 the utilities in Alberta filed a leave to appeal motion with the Supreme Court of Canada, the outcome and timing of which is unknown.

Eastern Canadian Electric Utilities

In October 2015 Newfoundland Power filed a 2016/2017 GRA with the PUB to set customer rates effective July 1, 2016. The Company is proposing an overall average increase in electricity rates of 3.1%. The GRA will include a full review of Newfoundland Power's costs, including cost of capital. The application is currently under review by the PUB. A public hearing is scheduled to begin at the end of the first quarter of 2016 and a decision on the application is expected by the end of the second quarter of 2016.

In October 2015 Maritime Electric filed a GRA with the IRAC to set customer rates effective March 1, 2016, on expiry of the *Prince Edward Island Energy Accord*. In January 2016 Maritime Electric and the Government of PEI entered into a 2016 General Rate Agreement covering the three-year period from March 1, 2016 through February 28, 2019. The agreement, which is subject to regulatory approval, is generally consistent with the GRA filed in October 2015, however, reflects an allowed ROE capped at 9.35% on a maximum average common equity component of capital structure of 40%. Under the agreement, the typical customer electricity cost increase will be limited to a maximum of 2.3% annually.

Significant Regulatory Proceedings

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

Regulated Utility	Application/Proceeding	Filing Date	Expected Decision
TEP	GRA for 2017	November 2015	Fourth quarter of 2016
UNS Electric	GRA for 2016	May 2015	Third quarter of 2016
Central Hudson	Reforming the Energy Vision	Not applicable	To be determined
FEI	2016 Cost of Capital Application	October 2015	Second quarter of 2016
FortisAlberta	2016/2017 Capital Tracker Application	May 2015	First quarter of 2016
	2016/2017 GCOC Proceeding	Not applicable	Second half of 2016
Newfoundland Power	GRA for 2016/2017	October 2015	Second quarter of 2016

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2015 and December 31, 2014.

Significant Changes in the Consolidated Balance Sheets between December 31, 2015 and December 31, 2014

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Regulatory assets – current and long-term	117	The increase was mainly due to: (i) an increase in regulatory deferred income taxes, mainly at FortisAlberta; (ii) the impact of foreign exchange on the translation of US dollar-denominated regulatory assets; and (iii) the deferral of various other costs as permitted by the regulators. The above-noted increases were partially offset by a reduction in regulatory assets at Central Hudson due to the offsetting of certain regulatory account balances, as approved by the regulator, and a decrease in the deferral for employee future benefits.
Utility capital assets	2,416	The increase primarily related to utility capital expenditures and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets, partially offset by depreciation and customer contributions.
Non-utility capital assets	(664)	The decrease was due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.
Goodwill	441	The increase was due to the impact of foreign exchange on the translation of US dollar-denominated goodwill.
Short-term borrowings	181	The increase was mainly due to higher short-term borrowings at FortisBC Energy and FortisBC Electric, largely to finance utility capital expenditures.
Regulatory liabilities – current and long-term	193	The increase was mainly due to the impact of foreign exchange on the translation of US dollar-denominated regulatory liabilities and higher rate stabilization accounts at FortisBC Energy, partially offset by a reduction in regulatory liabilities at Central Hudson due to the offsetting of certain regulatory account balances, as approved by the regulator.
Long-term debt (including current portion)	732	The increase was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely in support of energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.
Capital lease and finance obligations (including current portion)	(190)	The decrease was mainly due to the purchase of an additional ownership interest in the Springerville Unit 1 generating facility and the Springerville coal handling facilities at UNS Energy following the expiry of lease arrangements.
Deferred income tax liabilities	424	The increase was primarily due to tax timing differences mainly related to capital expenditures at the regulated utilities and the impact of foreign exchange on the translation of US dollar-denominated deferred income tax liabilities.
Shareholders' equity (before non-controlling interests)	1,189	The increase primarily related to: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans.

LIQUIDITY AND CAPITAL RESOURCES

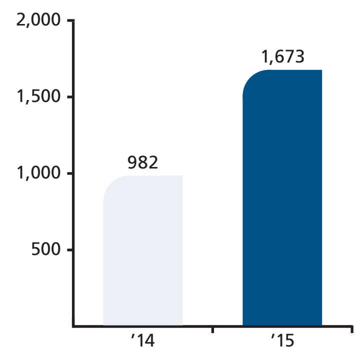
Summary of Consolidated Cash Flows

The table below outlines the Corporation's sources and uses of cash in 2015 compared to 2014, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows

Years Ended December 31 *($ millions)*	**2015**	2014	Variance
Cash, Beginning of Year	**230**	72	158
Cash Provided by (Used in):			
Operating Activities	**1,673**	982	691
Investing Activities	**(1,368)**	(4,199)	2,831
Financing Activities	**(346)**	3,361	(3,707)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**53**	14	39
Cash, End of Year	**242**	230	12

Cash Flow from Operating Activities *($ millions)*



Operating Activities: Cash flow from operating activities in 2015 was $691 million higher than in 2014. The increase was driven by higher cash earnings and favourable changes in working capital. The increase in cash earnings was driven by the acquisition of UNS Energy in August 2014. Earnings contribution from the Waneta Expansion and higher cash earnings at FortisAlberta also contributed to the increase. Favourable changes in working capital at FortisBC Energy and UNS Energy were partially offset by unfavourable changes at FortisAlberta.

Investing Activities: Cash used in investing activities in 2015 was $2,831 million lower than in 2014. The decrease was due to the acquisition of UNS Energy in August 2014 for a net cash purchase price of $2,745 million. Also contributing to the decrease were proceeds received from the sale of commercial real estate assets in June 2015 for $430 million, hotel assets in October 2015 for $365 million, and generation assets in Upstate New York in June 2015 for $77 million (US$63 million), compared to proceeds of $105 million (US$95 million) on the sale of Griffith in March 2014. The decrease was partially offset by an increase in capital expenditures of $518 million, driven by a full year contribution from UNS Energy and higher capital spending at most of the Corporation's regulated utilities, partially offset by lower non-regulated capital expenditures due to the completion of the Waneta Expansion and the sale of commercial real estate and hotel assets.

Financing Activities: Cash provided by financing activities in 2015 was $3,707 million lower than in 2014. The decrease was primarily due to financing associated with the acquisition of UNS Energy in August 2014 and the repayment of credit facility borrowings in 2015 using proceeds from the sale of commercial real estate and hotel assets. The acquisition of UNS Energy was financed from proceeds of $1,800 million, or $1,725 million net of issue costs, from the issue of convertible debentures, proceeds from the issuance of preference shares and credit facility borrowings. In October 2014 substantially all of the convertible debentures were converted into 58.2 million common shares of Fortis.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease and finance obligations, and net (repayments) borrowings under committed credit facilities for 2015 and 2014 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2015**	2014	Variance
UNS Energy [(1)]	**591**	–	591
Central Hudson [(2)]	**25**	33	(8)
FortisBC Energy [(3)]	**150**	–	150
FortisAlberta [(4)]	**149**	274	(125)
FortisBC Electric [(5)]	**–**	198	(198)
Newfoundland Power [(6)]	**75**	–	75
Caribbean Utilities [(7)]	**–**	57	(57)
Fortis Turks and Caicos [(8)]	**12**	92	(80)
Corporate [(9)]	**–**	539	(539)
Total	**1,002**	1,193	(191)

[(1)] In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures. In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes. In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured notes and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt.

[(2)] In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes. In March 2014 Central Hudson issued 10-year US$30 million unsecured notes with a floating interest rate of 3-month LIBOR plus 1%. The net proceeds were used to repay maturing long-term debt and for other general corporate purposes.

[(3)] In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings and for general corporate purposes.

[(4)] In September 2015 FortisAlberta issued 30-year $150 million 4.27% senior unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes. In September 2014 FortisAlberta issued $275 million senior unsecured debentures in a dual tranche of 10-year $150 million at 3.30% and 30-year $125 million at 4.11%. The net proceeds were used to repay maturing long-term debt, finance capital expenditures and for general corporate purposes.

[(5)] In October 2014 FortisBC Electric issued 30-year $200 million 4.00% senior unsecured debentures. The net proceeds were used to repay long-term debt and credit facility borrowings.

[(6)] In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

[(7)] In November 2014 Caribbean Utilities issued a total of US$50 million unsecured notes with terms to maturity ranging from 15 to 32 years and coupon rates ranging from 3.65% to 4.53%. The net proceeds were used to finance capital expenditures.

[(8)] In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes. In December 2014 Fortis Turks and Caicos issued 15-year US$80 million 4.75% unsecured notes. The net proceeds were used to repay inter-company loans with a direct subsidiary of Fortis.

[(9)] In June 2014 the Corporation issued US$213 million unsecured notes with terms to maturity ranging from 5 to 30 years and coupon rates ranging from 2.92% to 4.88%. The weighted average term to maturity was approximately 9 years and the weighted average coupon rate was 3.51%. Net proceeds were used to repay US dollar-denominated borrowings on the Corporation's committed credit facility and for general corporate purposes. In September 2014 the Corporation issued US$287 million unsecured notes with terms to maturity ranging from 7 to 30 years and coupon rates ranging from 3.64% to 5.03%. The weighted average term to maturity was approximately 12 years and the weighted average coupon rate was 4.11%. Net proceeds were used to repay long-term debt and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations

Years Ended December 31

($ millions)	**2015**	2014	Variance
UNS Energy	**(449)**	–	(449)
Central Hudson	**–**	(24)	24
FortisBC Energy	**(92)**	(6)	(86)
FortisAlberta	**–**	(200)	200
FortisBC Electric	**–**	(140)	140
Newfoundland Power	**(6)**	(35)	29
Caribbean Utilities	**(17)**	(19)	2
Fortis Turks and Caicos	**(4)**	(4)	–
Fortis Properties	**(34)**	(22)	(12)
Corporate	**–**	(293)	293
Total	**(602)**	(743)	141

Net (Repayments) Borrowings Under Committed Credit Facilities

Years Ended December 31

($ millions)	**2015**	2014	Variance
UNS Energy	**(199)**	61	(260)
FortisAlberta	**30**	3	27
FortisBC Electric	**–**	(54)	54
Newfoundland Power	**(47)**	65	(112)
Corporate	**(406)**	535	(941)
Total	**(622)**	610	(1,232)

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

In September 2014 Fortis issued 24 million First Preference Shares, Series M for gross proceeds of $600 million. The net proceeds were used to repay a portion of credit facility borrowings used to initially finance a portion of the acquisition of UNS Energy.

Common share dividends paid in 2015 totalled $232 million, net of $156 million of dividends reinvested, compared to $194 million, net of $81 million of dividends reinvested, paid in 2014. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.40 in 2015 compared to $1.28 in 2014. The weighted average number of common shares outstanding was 278.6 million for 2015 compared to 225.6 million for 2014.

Contractual Obligations

The Corporation's consolidated contractual obligations with external third parties in each of the next five years and for periods thereafter, as at December 31, 2015, are outlined in the following table.

Contractual Obligations

As at December 31, 2015 *($ millions)*	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Long-term debt	**11,240**	384	71	283	239	857	9,406
Interest obligations on long-term debt	**9,435**	536	512	507	495	488	6,897
Capital lease and finance obligations (1)	**2,478**	72	74	93	77	75	2,087
Renewable power purchase obligations (2)	**1,589**	93	93	92	92	92	1,127
Gas purchase obligations (3)	**1,449**	366	253	222	153	131	324
Power purchase obligations (4)	**1,440**	281	209	180	102	36	632
Long-term contracts – UNS Energy (5)	**1,057**	146	141	105	102	82	481
Capital cost (6)	**488**	19	19	19	19	19	393
Operating lease obligations (7)	**181**	12	11	11	11	8	128
Renewable energy credit purchase agreements (8)	**162**	13	13	13	13	13	97
Purchase of Springerville Common Facilities (9)	**147**	–	53	–	–	–	94
Employee future benefits funding contributions	**139**	49	12	8	9	9	52
Waneta Partnership promissory note	**72**	–	–	–	–	72	–
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other (10)	**71**	15	12	16	3	–	25
Total	**30,001**	1,989	1,476	1,552	1,318	1,885	21,781

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

(2) TEP and UNS Electric are party to 20-year long-term renewable PPAs totalling approximately US$1,148 million as at December 31, 2015, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities that have achieved commercial operation. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. These agreements have various expiry dates through 2035. TEP has entered into additional long-term renewable PPAs to comply with renewable energy standards of the State of Arizona; however, the Company's obligation to purchase power under these agreements does not begin until the facilities are operational. In February 2016 one of the generating facilities achieved commercial operation, increasing estimated future payments of renewable PPAs by US$58 million, which is not included in the table above.

(3) Certain of the Corporation's subsidiaries, mainly FortisBC Energy and Central Hudson, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2015. At Central Hudson, the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2015.

(4) Power purchase obligations include various power purchase contracts held by certain of the Corporation's subsidiaries, as described below.

FortisBC Energy

In March 2015 FortisBC Energy entered into an Electricity Supply Agreement with BC Hydro for the purchase of electricity supply to the Tilbury Expansion Project, with purchase obligations totalling $513 million as at December 31, 2015.

FortisBC Electric

Power purchase obligations for FortisBC Electric, totalling $292 million as at December 31, 2015, mainly include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term, as approved by the BCUC. The capacity and energy to be purchased under this agreement do not relate to a specific plant.

In addition, in November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"), allowing FortisBC Electric to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Contractual Obligations table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

FortisOntario

Power purchase obligations for FortisOntario, totalling $208 million as at December 31, 2015, primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Quebec Energy Marketing for the supply of electricity and capacity, both expiring in December 2019. 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 provides a minimum of 300 GWh of electricity per contract year.

Maritime Electric

Power purchase obligations for Maritime Electric, totalling $194 million as at December 31, 2015, primarily include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019 and November 2032, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power") expiring in February 2019.

Central Hudson

Central Hudson's power purchase obligations totalled US$124 million as at December 31, 2015. In June 2014 Central Hudson entered into a contract to purchase available installed 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. 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.

(5) UNS Energy has entered into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$440 million, US$261 million and US$63 million, respectively, as at December 31, 2015. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts. As a result of the restructuring of the ownership of the San Juan generating station in January 2016, a new coal supply agreement came into effect under which TEP's minimum purchase obligations are US$137 million, which is not included in the previous table.

(6) Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit.

(7) Operating lease obligations include certain office, warehouse, natural gas T&D asset, rail car, land easement and rights-of-way, and vehicle and equipment leases.

(8) UNS Energy is party to renewable energy credit purchase agreements, totalling approximately US$117 million as at December 31, 2015, to purchase the environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

(9) UNS Energy has entered into a commitment to exercise its fixed-price purchase provision to purchase an undivided 50% leased interest in the Springerville Common Facilities if the lease is not renewed, for a purchase price of US$106 million, with one facility to be acquired in 2017 and the remaining two facilities to be acquired in 2021.

(10) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including Performance Share Unit, Restricted Share Unit and Directors' Deferred Share Unit Plan obligations and asset retirement obligations.

Other Contractual Obligations

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $1.9 billion for 2016. Over the five years 2016 through 2020, the Corporation's consolidated capital expenditure program is expected to be approximately $9 billion, which has not been included in the Contractual Obligations table.

Other: 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 the U.S. Federal Energy Regulatory Commission ("FERC") for the recovery of the cost of and return on five high-voltage transmission projects totalling 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 a maximum commitment of US$182 million. As at December 31, 2015, no payment obligation is expected under this guarantee.

FortisBC Energy issued commitment letters to customers, totalling $33 million as at December 31, 2015, to provide Energy Efficiency and Conservation ("EEC") funding under the EEC program approved by the BCUC.

Caribbean Utilities is party to primary and secondary fuel supply contracts and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2016 is 20 million imperial gallons. Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $1,340 million as at December 31, 2015 have been excluded from the Contractual Obligations table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 8 to the Corporation's 2015 Audited Consolidated Financial Statements.

Capital Structure

The Corporation's principal businesses of regulated electric and gas utilities require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 35% common equity, 65% debt and preferred equity, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

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

Capital Structure

	2015		2014	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [(1)]	**11,950**	**54.8**	11,239	56.4
Preference shares	**1,820**	**8.3**	1,820	9.1
Common shareholders' equity	**8,060**	**36.9**	6,871	34.5
Total [(2)]	**21,830**	**100.0**	19,930	100.0

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

(2) Excludes amounts related to non-controlling interests

Excluding capital lease and finance obligations, the Corporation's capital structure as at December 31, 2015 was 53.7% debt, 8.5% preference shares and 37.8% common shareholders' equity (December 31, 2014 – 54.8% debt, 9.5% preference shares and 35.7% common shareholders' equity).

The improvement in the Corporation's capital structure was due to an increase in common shareholders' equity as a result of: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for the year ended December 31, 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans. The capital structure was also impacted by an increase in total debt due to the impact of foreign exchange on the translation of US dollar-denominated debt and new debt in support of energy infrastructure investment, partially offset by regular scheduled debt repayments and net repayments under committed credit facilities.

Credit Ratings

As at December 31, 2015, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A– / Stable (long-term corporate and unsecured debt credit rating)
DBRS	A (low) / Stable (unsecured debt credit rating)

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining reasonable levels of debt at the holding company level. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P affirmed the Corporation's long-term corporate credit rating at 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 credit rating under review with negative implications.

Capital Expenditure Program

Capital investment in energy infrastructure is required to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $276 million in maintenance and repairs was expensed in 2015 compared to approximately $203 million in 2014. The increase was largely due to a full year of expense for UNS Energy in 2015.

Gross consolidated capital expenditures for 2015 were approximately $2.2 billion. A breakdown of these capital expenditures by segment and asset category for 2015 is provided in the following table.

Gross Consolidated Capital Expenditures (1)

Year Ended December 31, 2015

	Regulated Utilities								Non-Regulated		
($ millions)	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Fortis Generation**	**Non-Utility** (2)	**Total**
Generation	321	1	–	–	3	9	107	**441**	**38**	**–**	**479**
Transmission	131	37	57	–	19	23	2	**269**	**–**	**–**	**269**
Distribution	135	102	134	358	38	121	16	**904**	**–**	**–**	**904**
Facilities, equipment, vehicles and other (3)	39	27	254	73	35	14	9	**451**	**–**	**28**	**479**
Information technology	43	14	15	21	8	8	3	**112**	**–**	**–**	**112**
Total	669	181	460	452	103	175	137	**2,177**	**38**	**28**	**2,243**

(1) Represents cash payments to construct utility capital assets, non-utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC.

(2) Includes capital expenditures of approximately $14 million at FAES, which is reported in the Corporate and Other segment

(3) Includes capital expenditures associated with the Tilbury Expansion at FortisBC Energy and Alberta Electric System Operator ("AESO") transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast. Gross consolidated capital expenditures of $2,243 million for 2015 were $91 million higher than $2,152 million forecast for 2015, as disclosed in the MD&A for the year ended December 31, 2014. The increase was driven by higher capital spending at FortisBC Energy primarily due to the timing of payments associated with the Tilbury Expansion and at FortisAlberta primarily due to the purchase of two Rural Electrification Associations ("REAs") for approximately $21 million in 2015, and due to the impact of foreign exchange associated with the translation of US dollar-denominated capital expenditures. The increase was partially offset by lower-than-forecast capital spending at the Waneta Expansion, due to the timing of payments, and at FAES.

Gross consolidated capital expenditures for 2016 are expected to be approximately $1.9 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2016 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures [(1)]

Year Ending December 31, 2016

	Regulated Utilities								Non-Regulated		
($ millions)	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Fortis Generation**	**Non-Utility [(2)]**	**Total**
Generation	162	2	–	–	2	24	73	**263**	**15**	**–**	**278**
Transmission	66	30	84	–	21	19	6	**226**	**–**	**–**	**226**
Distribution	168	142	129	311	29	110	23	**912**	**–**	**–**	**912**
Facilities, equipment, vehicles and other [(3)]	40	25	118	109	16	9	20	**337**	**–**	**3**	**340**
Information technology	49	29	18	21	11	12	5	**145**	**–**	**–**	**145**
Total	485	228	349	441	79	174	127	**1,883**	**15**	**3**	**1,901**

(1) Represents forecast cash payments to 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 AFUDC. Forecast capital expenditures for 2016 are based on a forecast exchange rate of US$1.00=CAD$1.38.

(2) Includes forecast capital expenditures of approximately $3 million at FAES, which is reported in the Corporate and Other segment

(3) Includes forecast capital expenditures associated with the Tilbury Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

The percentage breakdown of 2015 actual and 2016 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows.

Gross Consolidated Capital Expenditures

Year Ending December 31 *(%)*	**Actual 2015**	Forecast 2016
Growth [(1)]	**40**	36
Sustaining [(2)]	**44**	48
Other [(3)]	**16**	16
Total	**100**	100

(1) Includes capital expenditures associated with the Tilbury Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

(2) Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

(3) Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period 2016 through 2020, excluding the pending acquisition of ITC, gross consolidated capital expenditures are expected to be approximately $9 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 40% at Regulated Electric & Gas Utilities in the United States; 37% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 17% at Canadian Regulated Gas Utility; 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.

Actual 2015 and forecast 2016 midyear rate base for the Corporation's regulated utilities and 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.

The most significant capital projects that are included in the Corporation's base consolidated capital expenditures for 2015 and 2016 are summarized in the table below.

Significant Capital Projects [(1)]

($ millions) **Company**	**Nature of Project**	Pre-2015	**Actual 2015**	Forecast 2016	Forecast 2017–2020	Expected Year of Completion
UNS Energy [(2)]	Interest in Springerville Unit 1	23	**57**	–	–	2015
	Springerville Coal Handling Facilities Lease Buyout	–	**91**	–	–	2015
	Pinal Transmission Project	9	**84**	–	–	2015
	Residential Solar Program	–	**1**	22	90	Ongoing
Central Hudson [(2)]	Gas Main Replacement Program	7	**19**	29	135	Post-2020
FortisBC Energy	Tilbury LNG Facility Expansion [(3)]	145	**181**	105	15	2016
	Lower Mainland System Upgrade	4	**11**	50	362	2018
FortisAlberta	Pole-Management Program	159	**41**	42	94	Post-2020
Caribbean Utilities [(2)]	Generation Expansion	12	**61**	35	–	2016
Waneta Partnership	Waneta Expansion [(4)]	679	**36**	13	97	2015

(1) Represents utility capital asset and intangible asset expenditures, including both the capitalized interest and equity components of AFUDC, where applicable

(2) Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CAD$1.38 for 2016 through 2020

(3) Total project investment as at December 31, 2014 and 2015 includes approximately $43 million and $11 million, respectively, in non-cash capital accruals

(4) Includes the $72 million payment expected to be made in 2020 and excludes forecast capitalized interest of the minority partners, CPC/CBT, in the Waneta Partnership

UNS Energy completed three significant capital investments in 2015. In January 2015, upon expiration of the Springerville Unit 1 lease, UNS Energy purchased an additional ownership interest in Springerville Unit 1 for US$46 million. This purchase increased the ownership interest to 49.5%. Additionally, upon expiration of the Springerville Coal Handling Facilities lease in April 2015, UNS Energy purchased an ownership interest in the coal-handling assets for US$72 million. The Pinal Transmission Project at UNS Energy was also completed in 2015 at a total project cost of US$79 million. The project consisted of the construction of a 500-kilovolt transmission line in Pinal County that will increase the Company's import capacity from Gila River Unit 3 and the Palo Verde trading hub.

The Residential Solar Program at UNS Energy is a partnership with local solar companies for UNS Energy to own and install rooftop solar systems for residential customers. The total capital cost of the program through 2020 is expected to be approximately US$82 million, with approximately US$16 million expected to be spent in 2016.

The Gas Main Replacement Program at Central Hudson is a 15-year replacement program to eliminate and replace leakage-prone pipes throughout the gas distribution system. The proposed replacement program increases the rate of annual expenditures on pipe replacements to approximately US$20 million to expedite the replacement plan. Approximately US$15 million was spent on this program in 2015 and an additional US$21 million is expected to be spent in 2016. The majority of spending is expected post 2020.

FortisBC Energy's ongoing Tilbury LNG Facility Expansion, at an estimated total project cost of $440 million, will include a second LNG tank and a new liquefier, both to be in service around the end of 2016. FortisBC Energy received an Order in Council from the Government of British Columbia exempting the Tilbury LNG Facility project from further regulatory review. Key construction activities in 2015 were focused on construction of the storage tank and liquefaction process areas. Total project costs to the end of 2015 were approximately $326 million.

The Lower Mainland System Upgrade project at FortisBC Energy is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia. The project will be completed in two phases: (i) the Lower Mainland Intermediate Pressure System Upgrade project phase, which is focused on addressing pipeline condition issues; and (ii) the Coastal Transmission System phase, which is intended to increase security of supply by reducing the number of single points of failure. The project has an estimated capital cost of $427 million, with approximately $50 million forecast to be spent in 2016, and is expected to be completed in 2018. The BCUC approved the application to replace certain sections of intermediate pressure pipeline segments within the Greater Vancouver area in October 2015. The Coastal Transmission System phase was approved by a Special Direction by the Government of British Columbia in 2014 and will not be subject to further regulatory review.

During 2015 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program to extend the service life of existing poles and to replace poles when deterioration is beyond repair. The total capital cost of the program through 2020 is expected to be approximately $336 million. Approximately $41 million was spent on this program in 2015, for a total of $200 million spent to date.

Caribbean Utilities was the successful bidder for new generation capacity and entered into a design-build contract agreement to cover 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. Approximately US$48 million was spent on the project in 2015, with approximately US$25 million forecast to be spent in 2016. The project cost is estimated to be US$85 million and the plant is expected to be commissioned in mid-2016.

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. Fortis owns a 51% interest in the Waneta Partnership and operates and maintains the non-regulated investment. The capital cost of the Waneta Expansion, as reported in the Significant Capital Projects table, includes capitalized interest by Fortis during construction, as well as other eligible capitalized expenses, and a $72 million payment expected to be made in 2020 related to accrued development costs previously incurred by CPC/CBT. The table excludes approximately $50 million of forecast capitalized interest of the minority partners in the Waneta Partnership.

Additional Investment Opportunities

In addition to the Corporation's base consolidated capital expenditure forecast, management is pursuing additional investment opportunities within existing service territories. These additional investment opportunities, as discussed below, are not included in the Corporation's base capital expenditure forecast and also exclude the acquisition of ITC.

FortisBC Energy is pursuing additional LNG infrastructure investment opportunities, including a pipeline expansion to the proposed Woodfibre LNG site in Squamish, British Columbia and a further expansion of Tilbury. In December 2014 FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting these projects from further regulatory approval by the BCUC.

The pipeline expansion is conditional on Woodfibre LNG proceeding with its LNG export facility. The Woodfibre LNG plant has passed the British Columbia Environmental Assessment Office review and the Squamish First Nation approved an environmental certificate for the project in October 2015. These approvals are significant milestones; however, the project is pending a Federal Environmental Assessment. In addition, FortisBC Energy's pipeline expansion, at an estimated total project cost of up to $600 million, is also subject to various environmental approvals. A final investment decision by Woodfibre LNG is expected in 2016.

A further expansion of Tilbury is conditional upon having long-term contracts in place for the offtake of 70% of the additional liquefaction capacity, on average, for the first 15 years of operation. FortisBC Energy has a conditional agreement with Hawaiian Electric Company that would meet this requirement, subject to the regulatory approval process in Hawaii. The Corporation continues to have discussions with Hawaiian Electric Company, which is expected to be the primary offtaker, regarding the viability and scope of the project. Any resulting agreement would be subject to the approval of the Hawaii Public Utilities Commission.

The Corporation also has other significant opportunities that have not yet been included in the Corporation's capital expenditure forecast including, but 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.

Cash Flow Requirements

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

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis.

Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. For a discussion of the Corporation's cash flow requirements associated with the pending acquisition of ITC, refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" and "Subsequent Event" sections of this MD&A.

In April 2015 FortisBC Energy filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to $1 billion during the 25-month life of the shelf prospectus. In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures under the base shelf prospectus.

In June 2015 Fortis injected US$180 million of equity into TEP. Proceeds were used to repay credit facility borrowings in June 2015 and the balance was used to redeem bonds in August 2015 and provide additional liquidity to TEP. This equity injection fulfilled one of the commitments made by Fortis in order to receive regulatory approval for the acquisition of UNS Energy, and increased TEP's common equity component of capital structure to almost 50%, which is comparable with other regulated utilities in Arizona.

In May 2015 Caribbean Utilities completed a rights offering in which it raised gross proceeds of US$32 million through the issue of 2.9 million common shares. Fortis invested US$23 million in approximately 2.2 million common shares of Caribbean Utilities. The net proceeds from the rights offering were used by Caribbean Utilities to finance capital expenditures.

In October 2015 FortisAlberta filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to $500 million during the 25-month life of the shelf prospectus.

As at December 31, 2015, management expects consolidated fixed-term debt maturities and repayments to be $313 million in 2016 and to average approximately $260 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2015 and are expected to remain compliant in 2016.

Credit Facilities

As at December 31, 2015, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.6 billion, of which approximately $2.4 billion was unused, including $570 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, as well as large banks in the United States, with no one bank holding more than 20% of these facilities. Approximately $3.3 billion of the total credit facilities are committed facilities with maturities ranging from 2016 through 2020.

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

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	**Total as at December 31, 2015**	Total as at December 31, 2014
Total credit facilities [(1)]	2,211	1,354	**3,565**	3,854
Credit facilities utilized:				
Short-term borrowings	(511)	–	**(511)**	(330)
Long-term debt (including current portion) [(2)]	(71)	(480)	**(551)**	(1,096)
Letters of credit outstanding	(68)	(36)	**(104)**	(192)
Credit facilities unused	1,561	838	**2,399**	2,236

(1) Total credit facilities exclude a $300 million option to increase the Corporation's committed corporate credit facility, as discussed below.

(2) As at December 31, 2015, credit facility borrowings classified as long-term debt included $71 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2014 – $257 million).

As at December 31, 2015 and 2014, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

The UNS Utilities have a total of US$350 million ($484 million) in unsecured committed revolving credit facilities maturing in October 2020, with the option of two one-year extensions.

Central Hudson has a US$200 million ($277 million) unsecured committed revolving credit facility, maturing in October 2020, that is utilized to finance capital expenditures and for general corporate purposes. Central Hudson also has an uncommitted credit facility totalling US$25 million ($34 million).

FEI has a $700 million unsecured committed revolving credit facility, maturing in August 2018, that is utilized to finance working capital requirements, capital expenditures and for general corporate purposes.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2020, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2018. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2019, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2016.

Caribbean Utilities has unsecured credit facilities totalling approximately US$47 million ($65 million). Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$26 million ($36 million), maturing in September 2016.

Corporate and Other

Fortis has a $1 billion unsecured committed revolving 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 at December 31, 2015, the Corporation has not yet exercised its option for the additional $300 million. The Corporation also has a $35 million letter of credit facility, maturing in January 2017.

UNS Energy Corporation has a US$150 million ($208 million) unsecured committed revolving credit facility, maturing in October 2020, with the option of two one-year extensions.

CH Energy Group has a US$50 million ($69 million) unsecured committed revolving credit facility, maturing in July 2020, that can be utilized for general corporate purposes.

FHI has a $30 million unsecured committed revolving credit facility, maturing in April 2018, that is available for general corporate purposes.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $104 million as at December 31, 2015 (December 31, 2014 – $192 million), the Corporation had no off-balance sheet arrangements that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Regulated utility assets comprised approximately 96% of total assets of Fortis as at December 31, 2015 (December 31, 2014 – 93%). Approximately 96% of the Corporation's operating revenue[(1)] was derived from regulated utility operations in 2015 (2014 – 95%), and approximately 92% of the Corporation's operating earnings[(1)], excluding the gains on sale of non-core assets, were derived from regulated utility operations in 2015 (2014 – 91%). The Corporation operates nine utilities in different jurisdictions in Canada, the United States and the Caribbean, with no more than one-third of total assets located in any one regulatory jurisdiction.

Each of the Corporation's regulated utilities is subject to normal regulation that can affect future revenue and earnings. As a result, the utilities are subject to uncertainties faced by regulated entities, including approval by the respective regulatory authorities of electricity and gas rates that permit a reasonable opportunity to recover, on a timely basis, the estimated COS, including a fair rate of return on rate base and, in the case of utilities in the Caribbean, the continuation of licences. Generally, the ability of a utility to recover the actual COS and earn the approved ROE and/or ROA depends on achieving the forecasts established in the rate-setting processes. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudent cost of service and earn its allowed ROE, however, a utility is exposed to risks that inflationary increases may exceed the inflationary factor set by the regulator and that the utility may be unable to achieve productivity improvements. In the case of FortisAlberta's current PBR mechanism, there is a risk that capital expenditures may not qualify, or be approved, as a capital tracker where necessary.

Regulators approve the allowed ROEs and deemed capital structures of the utilities. Fair regulatory treatment that allows a utility to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining service quality, as well as ongoing capital attraction and growth. Rate applications establishing revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through a litigated public hearing process. There can be no assurance that resulting rate orders issued by the regulators will permit the regulated utilities to recover all costs actually incurred and to earn the expected or fair rates of return on an appropriate capitalization.

Electricity and gas infrastructure investments require the approval of the regulatory authorities, either through the approval of capital expenditure plans or revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or COS. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved. Capital cost overruns may not be recoverable in customer rates.

A failure to obtain acceptable rate orders, appropriate ROEs or capital structures as applied for may adversely affect the business carried on by the regulated utilities, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the issuance of long-term debt and other matters, which may, in turn, have a material adverse effect on the results of operations and financial position of the Corporation's regulated utilities. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

As an owner of an electricity distribution network under the *Electric Utilities Act (Alberta)*, FortisAlberta is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as a default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, FortisAlberta appointed EPCOR Energy Services (Alberta) Inc. ("EPCOR") as its regulated-rate provider. As a result of this appointment, EPCOR assumed all of FortisAlberta's rights and obligations in respect of these services. In the unlikely event that EPCOR is unable or unwilling to act as a regulated-rate provider or default supplier, and no other party is willing to act in this capacity, FortisAlberta would be required to act as a provider of electricity services to eligible customers under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If FortisAlberta could not secure outsourcing for these functions, it would need to administer these retail responsibilities by adding necessary staff, facilities and/or equipment.

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

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(1) Operating revenue and operating earnings are non-US GAAP measures and refer to total revenue, excluding Corporate and Other segment revenue and inter-segment eliminations, and net earnings attributable to common equity shareholders, excluding Corporate and Other segment expenses, respectively. Operating revenue and operating earnings are referred to by users of the consolidated financial statements in evaluating the performance of the Corporation's operating subsidiaries.

Risks Associated with the Pending Acquisition of ITC: ITC is a public company and its directors have fiduciary duties which may require them to consider competing offers to purchase the common stock of ITC as an alternative to the Acquisition. The agreement and plan of merger preserves the ability of the directors of ITC to accept a competing offer, in certain circumstances. Fortis may exercise its right to match such offer and, as a result, the purchase price could increase and other key transaction terms could change.

The closing of the acquisition of ITC, which is expected to occur in late 2016, is subject to normal commercial risks that the Acquisition will not close on the terms negotiated, or at all. Completion of the Acquisition remains subject to receipt of ITC and Fortis shareholder approvals, certain regulatory, state and federal approvals, and the satisfaction or waiver of other customary closing conditions contained in the agreement and plan of merger. The failure to obtain the required approvals or to satisfy or waive the conditions to closing may result in the termination of the agreement and plan of merger. Fortis intends to complete the Acquisition as soon as practicable after obtaining the required shareholder, regulatory and governmental approvals, and satisfying the other required closing conditions. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Corporation's ability to complete the Acquisition and on the Corporation's business, financial condition or results of operations. If the closing of the acquisition of ITC does not take place as contemplated, the Corporation could suffer material adverse consequences. Failure to complete the Acquisition would, in certain circumstances, result in the Corporation being required to pay a termination fee of up to US$280 million and other potential costs.

Fortis expects that the Acquisition will provide benefits to the Corporation, including 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. There is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation. Failure to realize the anticipated benefits of the acquisition of ITC may impact the financial performance of the Corporation, the price of its common shares and the ability of Fortis to continue to pay dividends on its common shares at rates consistent with the Corporation's dividend guidance, at current rates or at all.

Financing of the cash portion of the Acquisition is expected to 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. There can be no assurance that such financing sources will be available to Fortis at the desired time or at all, or on cost-efficient or commercially acceptable terms. As a result, there is no certainty that Fortis will reach a binding agreement with minority investors to complete the minority investment prior to closing of the Acquisition or at all. The Acquisition is not conditional upon Fortis securing one or more minority investors. Consummation of the Acquisition without completion of the contemplated minority investment could increase the consolidated indebtedness of the Corporation or result in the requirement for additional common equity and may have a negative impact on the Corporation's credit ratings and outlook and could result in additional financing costs and the failure to realize some, or all, of the expected benefits of the acquisition, including the extent to which the Acquisition is accretive. The Corporation obtained commitments for an aggregate of US$3.7 billion non-revolving term credit facilities. The commitments of the lenders to enter into these credit facilities is subject to certain customary conditions, which may result in such facilities becoming unavailable to Fortis in certain circumstances. If these credit facilities become unavailable, Fortis may not be able to complete the Acquisition.

While Fortis intends to become a U.S. Securities and Exchange Commission ("SEC") registrant and list its common shares on the New York Stock Exchange, there is no guarantee that it will be successful in this regard. If the Corporation is successful in this regard, it will be subject to increased regulatory compliance and may be subject to a greater risk of litigation.

The operations of ITC are conducted in US dollars and, following the Acquisition, the consolidated earnings and cash flows of Fortis will be impacted to a greater extent by fluctuations in the US dollar-to-Canadian dollar exchange rate. In particular, any decrease in the value of the US dollar relative to the Canadian dollar following the Acquisition could negatively impact the Corporation's net income as reported in Canadian dollars. Fortis may enter into forward foreign exchange contracts and utilize certain other derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past. There is no guarantee that such hedging strategies, if adopted, will be effective.

Fortis expects to incur a variety of costs in 2016 associated with completing the Acquisition. The majority of these costs will be non-recurring expenses related to financing and obtaining shareholder and regulatory approvals. Certain of these costs have already been incurred and other such costs will be incurred even if the Acquisition is ultimately not completed. Additional unanticipated acquisition-related costs may also be incurred in 2016.

Interest Rate Risk: Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs directly when they are applied in formulaic ROE automatic adjustment mechanisms or indirectly through a regulatory process of what constitutes an appropriate rate of return on investment, which may consider the general level of interest rates as a factor for setting allowed ROEs. Uncertainty exists regarding the duration of the current environment of low interest rates and the effect it may have on allowed ROEs of the Corporation's regulated utilities. If interest rates continue to remain at historically low levels, allowed ROEs could decrease. The continuation of a low interest rate environment could adversely affect the Corporation's ability to earn a reasonable ROE, which could have a negative effect on the financial condition and results of operations of the Corporation's regulated utilities. Also, if interest rates begin to climb, regulatory lag may cause a delay in any resulting increase in cost of capital and the regulatory allowed ROEs.

The Corporation and its subsidiaries may also be exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and refinancing of long-term debt. Central Hudson, FortisBC Energy and FortisBC Electric, however, have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate credit facilities for recovery from, or refund to, customers in future rates. There can be no assurance that such deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions. UNS Energy and Central Hudson use interest rate swaps and interest rate caps on variable-rate long-term debt to reduce risk associated with interest rates, as permitted by the regulators. At the Corporation's other regulated utilities, if the timing of issuance of, and the interest rates on, long-term debt are different from those forecast and approved in customer rates, the additional or lower interest costs incurred on the new long-term debt are not recovered from, or refunded to, customers in rates during the period that was covered by the approved customer rates. An inability to flow through interest costs to customers could have a material adverse effect on the results of operations and financial position of the utilities.

Excluding borrowings under long-term committed credit facilities, almost 90% of the Corporation's consolidated long-term debt as at December 31, 2015 had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2015.

Total Debt

As at December 31, 2015	*($ millions)*	*(%)*
Short-term borrowings	**511**	**4.4**
Utilized variable-rate credit facilities classified as long term	**551**	**4.7**
Variable-rate long-term debt (including current portion)	**333**	**2.8**
Fixed-rate long-term debt (including current portion)	**10,284**	**88.1**
Total	**11,679**	**100.0**

In 2015 the Corporation's regulated subsidiaries issued approximately $1 billion in long-term debt, all of which was at fixed interest rates ranging from 2.98% to 4.75%, with terms ranging from 10 to 30 years. The terms negotiated on new long-term debt demonstrate the ability of the Corporation and its utilities to raise long-term capital at attractive rates. Further information on the Corporation's consolidated long-term debt issuances is provided in the "Liquidity and Capital Resources" section of this MD&A.

A change in the level of interest rates could materially affect the measurement and disclosure of the fair value of long-term debt. The fair value of the Corporation's consolidated long-term debt, as at December 31, 2015, is provided in the "Financial Instruments" section of this MD&A.

Operating and Maintenance Risks: Storms and severe weather conditions, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the Corporation's utilities could result in service disruptions, leading to lower earnings and/or cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery. UNS Energy, Central Hudson and FortisBC Energy are exposed to various operational risks, associated with natural gas, such as: pipeline leaks, accidental damage to mains and service lines, corrosion in pipes, pipeline or equipment failure, other issues that can lead to outages and/or leaks, and any other accidents involving natural gas that could result in significant operational disruptions and/or environmental liability.

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

The operation of electricity T&D assets is also subject to risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. In addition, a significant portion of the utilities' infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged. The FortisBC utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and other acts of nature. UNS Energy, FortisBC Energy, FortisBC Electric and the Corporation's operations in the Caribbean region are subject to risk of loss from earthquakes.

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

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

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

Economic Conditions: Typical of utilities, economic conditions, such as changes in employment levels, personal disposable income, energy prices and housing starts, in the Corporation's service territories influence energy sales. Declines in energy sales could adversely impact the respective utilities' results of operations, net earnings and cash flows.

The business of UNS Energy is concentrated in the State of Arizona. In recent years economic conditions in Arizona have contributed significantly to a reduction in retail customer growth and lower energy usage by the Company's residential, commercial and industrial customers. While it is expected that economic conditions in Arizona will improve in the future, if they do not or if they should worsen, retail customer growth rates may stagnate or decline and customers' energy usage may further decline.

FortisBC Energy is affected by the trend in housing starts from single family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. The growth in new multi-family housing starts continues to significantly outpace that of new single-family homes, which may temper growth in gas distribution volumes.

Alberta's economy is impacted by a number of factors, including the level of oil and gas activity in the province, which is influenced by the market prices of oil and gas. A general and extended decline in economic conditions in Alberta or in other jurisdictions where the Corporation's utilities operate would be expected to have the effect of reducing demand for electricity over time. The regulated nature of utility operations, including various mitigating measures approved by certain regulators, helps reduce the impact that lower energy demand associated with poor economic conditions may have on the utilities' earnings. Significantly reduced electricity demand in the Corporation's service areas could materially reduce capital spending forecasts, and specifically capital spending related to new customer growth. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth. A severe and prolonged downturn in economic conditions could have a material adverse effect on the Corporation's results of operations, net earnings and cash flows despite regulatory measures, where applicable, available to compensate for reduced demand. In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for the electricity and gas they consume, thereby affecting the aging and collection of the utilities' trade receivables.

The Corporation's service territory in the Caribbean region has been impacted by challenging economic conditions over the past number of years. Activity in the tourism, real estate and construction sectors is closely tied to economic conditions in the region and changes in such activity affect customer electricity demand. Assets of Caribbean Regulated Electric Utilities comprise approximately 4% of the Corporation's total assets as at December 31, 2015.

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

Consolidated fixed-term debt maturities in 2016 are expected to total $313 million. The ability to meet long-term debt repayments when due will be dependent on the Corporation and its subsidiaries obtaining sufficient and cost-effective financing. The Corporation and its utilities have been successful at raising long-term capital at reasonable rates. Activity in the global capital markets may impact the cost and timing of issuance of long-term capital by the Corporation and its subsidiaries. While the future cost of raising capital could increase, the Corporation and its subsidiaries expect to continue to have reasonable access to capital in the near to medium terms.

The cost of renewed and extended credit facilities could increase going forward. Due to their regulated nature, any forecast changes in the cost of borrowing at the utilities are eligible to be reflected in customer rates.

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

In 2015 the following changes were made to debt credit ratings of the Corporation's utilities: (i) in February 2015 Moody's Investor Service ("Moody's") upgraded the debt credit ratings of UNS Energy to 'Baa1' from 'Baa2' and TEP, UNS Electric and UNS Gas to 'A3' from 'Baa1', and (ii) in July 2015 Fitch Ratings ("Fitch") downgraded Central Hudson's debt credit rating to 'A–' from 'A' and changed the rating outlook to stable from negative. Central Hudson's debt continues to be rated 'A' by S&P and 'A2' by Moody's, both with stable outlooks. In December 2015 DBRS confirmed FortisAlberta's debt credit rating of A(low) but revised its outlook to stable from positive. Also, in August 2015 Fitch confirmed TEP's credit rating of BBB+ but revised its outlook to positive from stable and in February 2016 Fitch withdrew its rating on TEP for commercial reasons at TEP's request. 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. For details on the Corporation's credit ratings, see the "Credit Ratings" section of this MD&A.

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

Political Risk: The regulatory framework under which utilities operate is impacted by significant shifts in government policy and/or changes in governments, which create uncertainty about public policy priorities and directions, particularly around energy and environmental issues. For details related to environmental issues, refer to the "Business Risk Management – Environmental Risks" section of this MD&A.

Information Technology and Cyber-Security Risks: As operators of critical energy infrastructure, the Corporation's utilities may face a heightened risk of cyber attacks. Information technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business and customer information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

The Corporation's subsidiaries have security measures, policies and controls designed to protect and secure the integrity of its information technology systems, and safeguard the confidentiality of corporate and customer information; however, cyber-security threats frequently change and require ongoing monitoring and detection capabilities. In the event the Corporation's utilities' information technology systems are breached, it could experience service disruptions, property damage, corruption or unavailability of critical data or confidential employee or customer information. If the breach is material in nature, it could adversely affect the financial performance of the Corporation, its reputation and standing with customers and regulators and expose it to claims of third-party damage. All of these factors could adversely affect the Corporation if not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies or, in the case of regulated utilities, through regulatory recovery.

Weather and Seasonality Risk: Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and could materially impact the operations, financial condition and results of operations of the electric utilities. In Canada, Arizona and New York State, cool summers may reduce air conditioning demand, while less severe winters may reduce electric heating load.

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

Regulatory deferral mechanisms are in place at certain of the Corporation's regulated utilities, including Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power, to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence of the above-noted regulatory deferral mechanisms could have a material adverse effect on the results of operations and financial position of the utilities.

Natural gas and coal-fired generating plants require continuous water flow for their operation. Shifts in weather or climate patterns, seasonal precipitation, the timing and rate of melting, run off, and other factors beyond the control of the Corporation, may reduce the water flow to UNS Energy's generation facilities. Any material reduction in the water flow to UNS Energy's generation facilities would limit the ability of the Company to produce and market electricity from those respective facilities and could have a material adverse effect on the results of operations and financial position of the Corporation. Any change in regulations or the level of regulation respecting the use, treatment and discharge of water, or respecting the licensing of water rights in the jurisdictions where UNS Energy operates could result in a material adverse effect on the results of operations and financial position of the Company.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River, where FortisBC Electric's dams and related facilities are located, in order to protect the environment. This adjustment could affect the amount of water available for generation at FortisBC Electric's plants or at plants operated by parties contracted to supply energy to FortisBC Electric. Prolonged adverse weather conditions could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Company's entitlement to capacity and energy under the Canal Plant Agreement.

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

The assets and earnings of Caribbean Utilities, Fortis Turks and Caicos and, to a lesser extent, Central Hudson, Newfoundland Power and Maritime Electric, are subject to hurricane risk. Certain of the Corporation's utilities may also be subject to severe weather events, including ice, wind and snow storms. Weather risks are managed through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. Under its T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster such as a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost-recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant weather event. Central Hudson is authorized to request, and the PSC has typically approved, deferral account treatment for incremental storm restoration costs. To qualify for deferral, storm costs must meet certain criteria as stipulated by the PSC. In most cases, the Corporation's other regulated utilities can apply to their respective regulators for relief from major uncontrollable expenses, including those related to significant weather-related events.

Earnings from non-regulated generation assets in Belize are sensitive to rainfall levels. The Waneta Expansion is included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing the hydrologic risk associated with hydroelectric generation. Prolonged adverse weather conditions, however, could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Waneta Expansion's entitlement to capacity and energy under the Canal Plant Agreement.

Commodity Price Risk: UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market prices of electricity and natural gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of natural gas. The operation of regulator-approved deferral mechanisms to flow through in customer rates the cost of natural gas, purchased power and coal serves to mitigate the impact on earnings of commodity price volatility. The risks have also been reduced by entering into various price-risk management strategies to reduce exposure to commodity rates, including the use of derivative contracts that effectively fix the price of natural gas, power and electricity purchases. The absence of such hedging mechanism in the future could result in increased exposure to market price volatility.

Certain of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affect the cost of fuel and purchased power. The risk is substantially mitigated by the utilities' ability to flow through to customers the cost of fuel and purchased power through base rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel, coal and purchased power will continue to exist in the future. Also, a severe and prolonged increase in such costs could materially affect FortisBC Energy, UNS Energy and Central Hudson, despite regulatory measures available to compensate for changes in these costs. The inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could have a material adverse effect on the utilities' results of operations and financial position.

Foreign Exchange Risk: The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar.

As at December 31, 2015, the Corporation's corporately issued US$1,535 million (December 31, 2014 – US$1,496 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2015, the Corporation had approximately US$3,137 million (December 31, 2014 – US$2,762 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded on the balance sheet in accumulated other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded on the balance sheet in accumulated other comprehensive income.

On an annual basis, it is estimated that a 5 cent, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.38 as at December 31, 2015 would increase or decrease earnings per common share of Fortis by approximately 4 cents, before considering the impact of the pending acquisition of ITC. Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: UNS Energy, Central Hudson and FortisBC Energy may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The above-noted utilities deal with credit quality institutions in accordance with established credit approval practices. These utilities did not experience any counterparty defaults in 2015 and do not expect any counterparties to fail to meet their obligations.

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

Competitiveness of Natural Gas in British Columbia: In FortisBC Energy's service territory, natural gas primarily competes with electricity for space and hot water heating load. Recently, there has been upward pressure on electricity rates in British Columbia, largely due to new investment required in the electricity generation and transmission sectors. In addition, the growth in North American natural gas supply, primarily from shale gas production, has resulted in a lower natural gas price environment. These factors have helped to improve natural gas competitiveness on an operating basis. Nevertheless, differences in upfront capital costs between electric and natural gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of natural gas on a full-cost basis.

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

There are other competitive challenges impacting the penetration of natural gas in new housing supply, such as the green attributes of the energy source and the type of housing being built. In recent years, FortisBC Energy has experienced a decline in the percentage of new homes installing natural gas compared with the total number of dwellings being built throughout British Columbia.

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

Natural Gas, Fuel and Electricity Supply: FortisBC Energy is dependent on a limited selection of pipeline and storage providers, particularly in the Lower Mainland, Interior and Vancouver Island service areas. Regional market prices, particularly at the Sumas market hub, have been higher than prices elsewhere in North America during peak winter periods, when regional pipeline and storage resources become constrained in serving the demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, FortisBC Energy is highly dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of FortisBC Energy could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers. The LNG storage facility on Vancouver Island helps to reduce this risk by providing short-term on-system supply during cold weather conditions or emergency situations.

Developments are occurring in the region that may increase the demand for gas supply from British Columbia. These include an increase in pipeline capacity to deliver gas from British Columbia to markets outside of British Columbia and the potential development of large-scale LNG facilities to export gas. British Columbia has significant natural gas resources that are expected to be sufficient to meet incremental demand requirements and to continue to supply existing markets. It is uncertain at this time, however, how the pace and location of infrastructure development to connect production to new and existing markets could impact the Corporation's access to supply at fair market prices.

The UNS Utilities are dependent on third parties to supply fuel, including natural gas and coal. Disruption of fuel supply could impair the ability of the Companies to deliver electricity or gas or generate electricity and could adversely affect operations. In addition, a loss of coal suppliers or the inability to renew existing coal or natural gas contracts at favorable terms could significantly affect the ability to serve customers and adversely affect the financial condition and the results of operations of the UNS Utilities.

Newfoundland Power is dependent on Newfoundland Hydro for approximately 93% of its customers' energy requirements and Maritime Electric is dependent on NB Power for approximately 75% of its customers' energy requirements. The Corporation's utilities in the Caribbean are dependent on third parties for the supply of all of their fuel requirements in the operation of their diesel-powered generating facilities. A shortage or interruption of the supply of electricity or fuel for the above utilities could have a material impact on their operations.

Newfoundland Power experienced losses of electricity supply from Newfoundland Hydro in January 2013 and January 2014, which disabled it from meeting all of its customers' requirements. The PUB is conducting an inquiry and hearing into these system supply issues and related power interruptions. To the extent it is able, Newfoundland Power intends to participate in these reviews in 2016. As well, the Government of Newfoundland and Labrador engaged consultants to complete an independent review of the current electricity system in the province.

Future changes in energy supply costs at Newfoundland Power, 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.

Power Purchase and Capacity Sale Contracts: FortisBC Electric's indirect customers are served by the Company's wholesale customers, who themselves are municipal utilities. The municipal utilities may be able to obtain alternate sources of energy supply, which would result in decreased demand, higher customer rates and, in extreme cases, could ultimately lead to an inability by FortisBC Electric to fully recover its COS in customer rates.

Additionally, the Corporation's regulated electric utilities periodically enter into various power purchase contracts and resale contracts for excess capacity with third parties. Upon expiry of the contracts, there is a risk that the utilities may not be able to secure extensions of such contracts. If the contracts are not extended, there is a risk of the utilities not being able to obtain alternate supplies of similarly priced electricity or not being able to secure additional capacity resale contracts. The utilities are also exposed to risk in the event of non-performance by counterparties to the various power purchase and resale contracts.

Employee Future Benefit Plan Performance and Funding Requirements: Fortis and the majority of its subsidiaries maintain a combination of defined benefit pension and/or OPEB plans for certain of their employees. Approximately 63% of the Corporation's total employees are members of defined benefit pension plans and approximately 72% of employees are members of OPEB plans.

The employee future benefit plans are subject to judgments utilized in the actuarial determination of the projected benefit obligation and related net benefit cost. The primary assumptions utilized by management are the expected long-term rate of return on assets, the discount rate and the health care trend rate used to value the projected benefit obligation. For a discussion of the critical accounting estimates associated with employee future benefit plans, refer to the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

The projected benefit obligation and related net benefit cost can be affected by changes in the global financial and capital markets. There is no assurance that the employee future benefit plan assets will earn the assumed long-term rates of return. Market-driven changes impacting the performance of the employee future benefit plan assets may result in material variations from the assumed long-term rates of return on the assets, which may cause material changes in future plan funding requirements from current estimates and future net benefit cost. Market-driven changes impacting the discount rates or the health care trend rate may also result in material changes in future plan funding requirements from current estimates and future net benefit cost.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process, as it affects the measurement of net benefit cost, future funding requirements and the projected benefit obligation.

Jointly Owned and Operated Generating Units: Certain of the generating stations from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities and, therefore, may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have limited or no discretion in managing the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed with environmental compliance requirements which could require significant capital expenditures or the closure of such generating stations. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP. In particular, TEP is subject to disagreement and litigation by third-party owners with respect to the existing agreements for Springerville Unit 1. As a result of these disagreements and pending litigation, the third-party owners have and may continue to refuse to pay some or all of their pro rata share of Springerville Unit 1 costs and expenses. For further details, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Technology Developments and Energy Efficiency: New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to have a significant impact on retail sales, which could negatively impact various utilities' results of operations, net earnings and cash flows. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. Utilities are promoting demand-side management programs designed to help customers reduce their energy usage.

Research and development activities are ongoing for new technologies that produce power, enable more efficient storage of energy, or reduce power consumption. These technologies include renewable energy, customer-owned generation, appliances, battery storage, equipment and control systems. Advances in these, or other technologies, could have a significant impact on retail sales which could negatively impact the results of operations, net earnings and cash flows of utilities.

Environmental Risks: The Corporation's electric and gas utilities are subject to inherent environmental risks, as well as environmental laws and regulations, as discussed below.

Inherent Environmental Risks

The Corporation's electric and gas utilities are subject to inherent risks, including fires, contamination of air, soil or water from hazardous substances, natural gas emissions and emissions from the combustion of fuel required in the generation of electricity. Risks associated with fire damage are related to weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims in connection with fires on land on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Inherent risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the transportation, handling and storage of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. Additional risks include environmental reclamation associated with coal mines that supply generating stations in which the Corporation has an ownership interest.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by insurance. For further information, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

Environmental Laws and Regulations

The Corporation's electric and gas utilities are subject to numerous federal, state and provincial environmental laws and regulations that may increase its cost of operations or expose it to environmental litigation and liabilities. Existing environmental laws and regulations may be revised or new environmental laws and regulations may be adopted or become applicable to the Corporation's operations. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on the results of operations of the Corporation. The utilities would request that additional costs resulting from environmental laws and regulations be recovered from customers in future rates. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, and the requirement for environmental impact assessments and remediation work. It is possible that other developments may lead to increasingly strict environmental laws and enforcement policies, and claims for damages to property or persons resulting from the operations of the Corporation's subsidiaries, any one of which could result in substantial costs or liabilities to the subsidiaries.

The management of greenhouse gas emissions is a specific environmental concern of the Corporation's regulated utilities in Canada and the United States, primarily due to new and emerging federal, provincial and state greenhouse gas laws, regulations and guidelines. In British Columbia, the Government of British Columbia's Energy Plan, *Carbon Tax Act*, *Clean Energy Act*, *Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act* affect, or may potentially affect, the operations of FortisBC Energy and FortisBC Electric. The utilities continue to assess and monitor the impact that the Government's Energy Plan and the *Clean Energy Act* may have on future operations.

In August 2015 the United States Environmental Protection Agency ("EPA") issued the Clean Power Plan ("CPP") limiting carbon emissions from existing and new fossil fuelled power plants. The CPP establishes state-level carbon emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets carbon emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. The CPP will require a shift in generation from coal to natural gas and renewables and could lead to the early retirement of coal generation in Arizona within the 2022 to 2030 compliance time-frame. UNS Energy is currently in the process of transitioning its generation resource mix, as appropriate, in order to reduce carbon emissions. The Company will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop compliance strategies. UNS Energy is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. The Company cannot predict the ultimate outcome of these matters.

The EPA incorporated the compliance obligations for existing power plants located on Indian nations, including 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. UNS Energy will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at the facilities. The Company 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. UNS Energy 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.

If any of the coal-fired generation plants, or coal-handling facilities, from which UNS Energy obtains power are closed prior to the end of their useful life in response to recent or future changes in environmental regulation, the Company could be required to recognize a material impairment of its assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any such generating stations may force UNS Energy to incur higher costs for replacement capacity and energy. The Company may not be permitted recovery of these costs in customer rates.

In addition, early closures of certain generating units could require UNS Energy to redeem some or all tax-exempt bonds associated with the respective generating units. As at December 31, 2015, approximately 43% of UNS Energy's generating capacity was fuelled by coal.

Environmental laws and regulations have given rise to environmental liabilities at certain of the Corporation's utilities. TEP is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has an ownership interest and is obligated to pay similar costs at the coal mines that supply these generating stations. As at December 31, 2015, TEP has recognized approximately US$25 million in mine reclamation obligations, representing the present value of the estimated future liability. While TEP has recorded the portion of its obligations for such reclamation costs that can be determined at this time, the total costs and timing of final reclamation at these sites are unknown and could be substantial. TEP currently recovers final mine reclamation costs through regulator-approved mechanisms as costs are paid to the coal suppliers.

Central Hudson is exposed to environmental contingencies associated with manufactured gas plants ("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 ("DEC") 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 PSC, the Company is currently permitted to recover MGP site investigation and remediation costs in customer rates.

The Corporation believes that it and its subsidiaries are materially compliant with the environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. With the exception of the mine reclamation costs at TEP and the MGP remediation liabilities at Central Hudson, as noted above, as at December 31, 2015, there were no material environmental liabilities recognized in the Corporation's 2015 Audited Consolidated Financial Statements. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could have a material adverse effect on the results of operations and financial position of the utilities.

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

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

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

Loss of Service Area: 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 the Company 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 the Company 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.

Within certain portions of FortisAlberta's service territory, REAs have been granted by the AUC the right to provide electric distribution service to their eligible members. Members eligible to receive electric distribution service from an REA are those who meet the specific eligibility criteria defined in the integrated operating agreements between the Company and REA. In general, this eligibility criteria has limited the provision of service to customers whose land is used for agricultural activity or as a rural estate property. This historical arrangement has been challenged by some self-operating REAs that are seeking to expand their services to a broader range of customers within the service area that overlaps that of the Company. FortisAlberta is actively resisting these efforts on the part of these self-operated REAs, as it believes the legislative scheme in Alberta does not support this type of competition between the regulated utility and these small rural electricity cooperatives. There is a risk that the efforts of these self-operating REAs to expand their services to a broader range of customers could increase their ability to serve customers in competition with the Company.

The consequence to FortisAlberta of a municipality purchasing its distribution assets or an REA serving more customers in its service territory would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. A significant reduction of rate base could have a material adverse effect on the results of operations and financial position of FortisAlberta.

Continued Reporting in Accordance with US GAAP: In January 2014 the Ontario Securities Commission ("OSC") issued a relief order which permits the Corporation and its reporting issuer subsidiaries in Canada to continue to prepare their financial statements in accordance with US GAAP until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after the Corporation or its reporting issuer subsidiaries ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board ("IASB") for the mandatory application of a standard within International Financial Reporting Standards ("IFRS") specific to entities with activities subject to rate regulation.

If the OSC relief does not continue as detailed above, the Corporation and its reporting issuer subsidiaries would then be required to become SEC registrants in order to continue reporting under US GAAP, or adopt IFRS. The IASB has released an interim, optional standard on Regulatory Deferral Accounts and continues to work on a project focusing on accounting specific to rate-regulated activities. It is not yet known when this project will be completed or whether IFRS will, as a result, include a permanent, mandatory standard to be applied by entities with activities subject to rate regulation. In the absence of a permanent standard for rate-regulated activities, the application of IFRS could result in volatility in the Corporation's earnings and earnings per common share as compared to those which would otherwise be recognized under US GAAP. In connection with the pending acquisition of ITC, Fortis expects to become a registrant with the SEC. As an SEC registrant, Fortis would be entitled under applicable Canadian laws to continue to prepare its consolidated financial statements in accordance with US GAAP.

Changes in Tax Legislation: The Corporation and its subsidiaries are subject to changes in tax legislation in Canada, the United States and other international jurisdictions.

Canadian Tax Legislation

During 2015 there were elections at the federal level and several provincial jurisdictions in Canada. A change in government can result in the passing of new tax legislation, including a change in rates of taxation. The new federal and provincial budgets are expected to be delivered in early 2016 and any resulting changes could have an impact on the Corporation and its Canadian subsidiaries. Any changes in tax legislation could affect the Corporation's results of operations, cash flows and financial position.

U.S. Tax Legislation

In 2015 the U.S. Congress enacted legislation approving the use of bonus depreciation through to 2019, subject to a phase out schedule reducing allowable rates to 50% in 2015 through 2017, 40% in 2018 and 30% in 2019. While this legislation provides greater certainty for planning purposes and reduces the cash tax burden of the Corporation's subsidiaries in the United States, any changes in this or other tax legislation in the United States could affect the Corporation's results of operations, cash flows and financial position.

International Tax Legislation

Fortis conducts business in certain tax-free jurisdictions, including certain countries in the Caribbean and Belize. Canada requires the governments of certain tax-free jurisdictions to enter a Tax Information Exchange Agreement ("TIEA"), which permits dividends paid from those jurisdictions to be exempt from tax when received in Canada. This legislation allows Fortis to receive a tax-free return of capital from the Caribbean. Certain legislation also provides a mechanism for the repayment of upstream loans that were previously used as a tax-deferred repatriation of earnings. The Corporation has approximately $79 million of upstream loans from its Caribbean subsidiaries, which are required to be repaid by August 2016. The Corporation expects to repay these loans, as required.

A TIEA has not yet been negotiated between Canada and Belize and there are no indications that Canada will conclude negotiations with the GOB in the near future. Until a TIEA is in place, active business earnings in Belize cannot be repatriated to Canada on a tax-free basis; however, the GOB has signed on to the Convention on Mutual Administrative Assistance in Tax Matter, which excludes Belize as a "non-qualifying country". As a result, the Corporation is not required to accrue tax on its active business income from Belize, whether or not repatriated to Canada.

In October 2015 the Organization for Economic Co-operation and Development ("OECD") released its final reports in connection with its action plan to address Base Erosion and Profit Sharing ("BEPS Action Plan"). The basis of the BEPS Action Plan is to identify and curb aggressive tax planning and practices, as well as monitor the international tax systems. Canada has not yet implemented the recommendations of the OECD report into tax treaties and domestic law; however, if it were to be enacted under Canadian tax legislation the Corporation would be required to assess the impacts and determine whether any changes to existing tax practices are required.

Access to First Nations' Lands: FortisBC Energy and FortisBC Electric provide service to customers on First Nations' lands and maintain gas facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the service areas of FortisBC Energy and FortisBC Electric is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as FortisBC Energy and FortisBC Electric. However, there can be no certainty that the settlement process will not have a material adverse effect on FortisBC Energy and FortisBC Electric's results of operations and financial position.

The Supreme Court of Canada decided in 2010 that, before issuing regulatory approvals for the addition of new facilities, the BCUC must consider whether the Crown has a duty to consult and accommodate First Nations, if necessary, and if so, whether the consultation and accommodation by the Crown have been adequate. This may affect the timing, cost and likelihood of the BCUC's approval of certain capital projects of FortisBC Energy and FortisBC Electric.

FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual First Nations band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to the Company and, therefore, may have a material adverse effect on FortisAlberta.

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

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

CHANGES IN ACCOUNTING POLICIES

The new US GAAP accounting policies that are applicable to, and were adopted by, Fortis, effective during 2015, are described as follows.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity: The Corporation prospectively adopted Accounting Standards Update ("ASU") No. 2014-08 that changes the criteria and disclosures for reporting discontinued operations. As a result, the sale of commercial real estate and hotel assets and the sale of non-regulated generation assets in 2015 did not meet the criteria for discontinued operations. The sales are consistent with the Corporation's focus on its core utility business and, therefore, do not represent a strategic shift in operations.

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period: The Corporation early adopted ASU No. 2014-12 that resolves diversity in practice for employee share-based payments with performance targets that can entitle an employee to benefit from an award regardless of if they are rendering services at the date the performance target is achieved. The adoption of this update was applied prospectively and did not have a material impact on the Corporation's 2015 Audited Consolidated Financial Statements.

Simplifying the Presentation of Debt Issuance Costs: The Corporation early adopted ASU No. 2015-03 that requires debt issuance costs to be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The adoption of this update was applied retrospectively and resulted in the reclassification of debt issuance costs of approximately $65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014. Additionally, the Corporation early adopted ASU No. 2015-15 that clarifies the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements. The update permits an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The adoption of this update was applied retrospectively and did not have a material impact on the Corporation's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes: The Corporation early adopted ASU No. 2015-17 that requires deferred tax assets and liabilities to be classified and presented as long term on the consolidated balance sheet. The adoption of this update was applied retrospectively and resulted in the reclassification of current deferred income taxes assets of $158 million, long-term deferred income tax assets of $62 million, and current deferred income tax liabilities of $9 million to long-term deferred income tax liabilities on the consolidated balance sheet as at December 31, 2014. As a result, the Corporation also reclassified current regulatory assets of $18 million, current regulatory liabilities of $19 million, and long-term regulatory liabilities of $91 million, to long-term regulatory assets on the consolidated balance sheet as at December 31, 2014, all associated with regulatory deferred income taxes.

FUTURE ACCOUNTING PRONOUNCEMENTS

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

Revenue from Contracts with Customers: ASU No. 2014-09 was issued in May 2014 and the amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the IASB to improve financial reporting by creating common revenue recognition guidance for US GAAP and IFRS that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. ASU No. 2015-14 was issued in August 2015 and the amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The majority of the Corporation's revenue is generated from energy sales to customers based on published tariff rates, as approved by the respective regulators, and is expected to be in the scope of ASU No. 2014-09. Fortis has not yet selected a transition method and is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures. The Corporation plans to have this assessment substantially complete by the end of 2016.

Amendments to the Consolidation Analysis: ASU No. 2015-02 was issued in February 2015 and the amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following with regard to limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. The adoption of this update is not expected to materially impact the Corporation's consolidated financial statements, however, it is expected to change the Corporation's 51% controlling ownership interest in Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional note disclosure.

FINANCIAL INSTRUMENTS

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

Financial Instruments

Liability as at December 31	2015		2014	
($ millions)	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	56	59	53	56
Long-term debt, including current portion	11,240	12,614	10,501	12,237

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

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

Financial Instruments Carried at Fair Value

As at December 31 ($ millions)	Fair value hierarchy	2015	2014
Assets			
Energy contracts subject to regulatory deferral (1) (2) (3)	Levels 2/3	7	3
Energy contracts not subject to regulatory deferral (1) (2)	Level 3	2	1
Available-for-sale investment (4) (5)	Level 1	33	–
Assets held for sale	Level 2	9	–
Other investments (4)	Level 1	12	5
Total gross assets		63	9
Less: Counterparty netting not offset on the balance sheet (6)		(6)	(3)
Total net assets		57	6
Liabilities			
Energy contracts subject to regulatory deferral (1) (2) (7)	Levels 1/2/3	78	72
Energy contracts not subject to regulatory deferral (1) (2)	Level 3	–	1
Energy contracts – cash flow hedges (2) (8)	Level 3	–	1
Interest rate swaps – cash flow hedges (8)	Level 2	5	5
Total gross liabilities		83	79
Less: Counterparty netting not offset on the balance sheet (6)		(6)	(3)
Total net liabilities		77	76

(1) The fair value of the Corporation's energy contracts is recorded in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in rates as permitted by the regulators, with the exception of long-term wholesale trading contracts.

(2) Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and those that qualify as cash flow hedges.

(3) Includes $2 million – level 2 and $5 million – level 3 (2014 – $3 million – level 3)

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

(5) The cost of the available-for-sale investment was $35 million and unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

(6) Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.

(7) Includes $1 million – level 1, $52 million – level 2 and $25 million – level 3 (2014 – $2 million – level 1, $35 million – level 2 and $35 million – level 3)

(8) The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships and transmission and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

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

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

As at December 31, 2015, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recorded in earnings. As at December 31, 2015, unrealized losses of $74 million (December 31, 2014 – $69 million) were recognized in regulatory assets and unrealized gains of $3 million were recognized in regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral

In June 2015 UNS Energy entered into long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with the ratepayer through UNS Energy's rate stabilization accounts.

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on lease debt, and held a power purchase swap, that expired in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $1 million.

Central Hudson holds interest rate cap contracts expiring in 2016 and 2017 on bonds with a total principal amount of US$64 million. Variations in the interest costs of the bonds, including any gains or losses associated with the interest rate cap contracts, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator and do not impact earnings.

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

Volume of Derivative Activity

As at December 31, 2015, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity *(year)*	Contracts *(#)*	2016	2017	2018	2019	2020	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts *(GWh)*	2019	8	1,043	730	438	219	–	–
Electricity power purchase contracts *(GWh)*	2017	28	1,027	145	–	–	–	–
Gas swap and option contracts *(PJ)*	2018	154	40	10	4	–	–	–
Gas purchase contract premiums *(PJ)*	2024	89	91	42	38	22	22	64
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2016	6	1,310	–	–	–	–	–

CRITICAL ACCOUNTING ESTIMATES

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

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

As at December 31, 2015, Fortis recognized a total of $2,532 million in regulatory assets (December 31, 2014 – $2,415 million) and $1,638 million in regulatory liabilities (December 31, 2014 – $1,445 million).

For a further discussion of the nature of regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Depreciation and Amortization: Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2015, the Corporation's consolidated capital assets and intangible assets were approximately $20.1 billion, or approximately 70%, of total consolidated assets compared to approximately $18.3 billion, or approximately 70%, of total consolidated assets as at December 31, 2014. Depreciation and amortization was $873 million for 2015 compared to $688 million for 2014.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-asset retirement obligation ("ARO") removal costs in depreciation, with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. The estimate of non-ARO removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2015 was $1,060 million, an increase of $109 million from $951 million as at December 31, 2014, mainly due to the impact of foreign exchange associated with the translation of US dollar-denominated non-ARO removal cost liabilities.

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

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

Effective January 1, 2015, FortisAlberta's depreciation and amortization rates were changed as a result of a technical update to its last depreciation study, which was completed as of December 31, 2010. A technical update adjusts depreciation and amortization rates based on current capital asset balances, while retaining the depreciation parameters established in the last approved depreciation study. As a result, FortisAlberta's depreciation and amortization expense were reduced by approximately $7 million in 2015.

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

Assessment for Impairment of Goodwill and Indefinite-Lived Intangible Assets: The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill and indefinite-lived intangible assets, and any impairment provision is charged to earnings. The annual impairment test is performed as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No such event or change in circumstances occurred during 2015 or 2014.

As at December 31, 2015, consolidated goodwill totalled approximately $4.2 billion (December 31, 2014 – $3.7 billion). Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights and totalled approximately $106 million as at December 31, 2015 (December 31, 2014 – $77 million).

Fortis performs an annual internal quantitative assessment for each reporting unit. For those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

In calculating goodwill impairment, Fortis determines those reporting units that will have fair value estimated by an external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, then a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, is also performed by an external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

No impairment provisions were required in either 2015 or 2014 with respect to goodwill or indefinite-lived intangible assets.

Employee Future Benefits:

Defined Benefit Pension Plans

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

The expected weighted average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2016, is 6.17%, which is down from 6.25% used for 2015. The decrease in the average long-term rate of return reflects shifting of plan assets from equities to fixed income assets. The defined benefit pension plan assets experienced total positive returns of approximately $30 million in 2015 compared to expected positive returns of $140 million. The expected long-term rates of return on pension plan assets are developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2015, and to determine net pension cost for 2016, is 4.21%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2014, and to determine net pension cost for 2015, of 4.00%. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year, except as follows for UNS Energy. UNS Energy adopted the spot rate methodology for determining net pension cost for 2016.

There was a $26 million increase in consolidated defined benefit net pension cost for 2015 compared to 2014, mainly due to the acquisition of UNS Energy in August 2014, and foreign currency translation impacts. Any increases in defined benefit net pension cost at the regulated utilities for 2016 are expected to be recovered from customers in rates, subject to regulatory lag and forecast risk at certain of the utilities.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2015 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2015 Audited Consolidated Financial Statements.

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

Year Ended December 31, 2015

(Decrease) increase *($ millions)*	**Net pension benefit cost**	**Projected benefit obligation** [(1)]
Impact of increasing the rate of return assumption by 100 basis points	(24)	–
Impact of decreasing the rate of return assumption by 100 basis points	20	(44)
Impact of increasing the discount rate assumption by 100 basis points	(44)	(370)
Impact of decreasing the discount rate assumption by 100 basis points	51	469

[(1)] At FortisBC Energy and FortisBC Electric, certain defined benefit pension plans have pension indexing provisions which provide for a portion of investment returns to be allocated in order to provide for indexing of pension benefits. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation. The direction of the impact of a change in the rate of return assumption at FortisBC Energy and FortisBC Electric is also the result of the methodology for determining the pension indexing assumption.

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

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

As at December 31, 2015, for all defined benefit pension plans, the Corporation had consolidated projected benefit obligations of $2,828 million (December 31, 2014 – $2,604 million) and consolidated plan assets of $2,466 million (December 31, 2014 – $2,216 million), for a consolidated funded status in a liability position of $362 million (December 31, 2014 – $388 million). During 2015, the Corporation recognized consolidated net pension benefit cost of $97 million (2014 – $71 million).

OPEB Plans

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and the accumulated benefit obligation. Similar assumptions as described above, except for the assumption of the expected long-term rate of return on pension plan assets, which is applicable only to the OPEB plans at UNS Energy and Central Hudson, along with the health care cost trend rate, were also utilized by management in determining net OPEB cost and accumulated benefit obligation.

The OPEB plan assets at UNS Energy and Central Hudson experienced no returns in 2015 compared to expected positive returns of approximately $12 million.

The following table provides the sensitivities associated with a 100 basis point change in the health care cost trend rate and the discount rate on 2015 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2015 Audited Consolidated Financial Statements.

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

Year Ended December 31, 2015

Increase (decrease) *($ millions)*	**Net OPEB cost**	**Accumulated benefit obligation**
Impact of increasing the health care cost trend rate assumption by 100 basis points	7	51
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(5)	(43)
Impact of increasing the discount rate assumption by 100 basis points	(6)	(71)
Impact of decreasing the discount rate assumption by 100 basis points	9	85

Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net OPEB cost from forecast net OPEB cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2015, for all OPEB plans, the Corporation had consolidated accumulated benefit obligations of $574 million (December 31, 2014 – $564 million) and consolidated plan assets of $181 million (December 31, 2014 – $154 million), for a consolidated funded status in a liability position of $393 million (December 31, 2014 – $410 million). During 2015, the Corporation recognized consolidated net OPEB benefit cost of $27 million (2014 – $21 million).

AROs: The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. There are also uncertainties in estimating future asset retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, removal of certain distribution system assets from rights-of-way at the end of the life of the systems and the remediation of certain land, no amounts were recognized as at December 31, 2015 and 2014, with the exception of AROs recognized by UNS Energy, Central Hudson and FortisBC Electric.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and T&D assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits and interconnection facilities agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

As at December 31, 2015, the Corporation's total AROs were $49 million (December 31, 2014 – $37 million). UNS Energy's AROs were primarily associated with TEP's generation and photovoltaic assets; Central Hudson's AROs were primarily associated with asbestos remediation; and FortisBC Electric's AROs were associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from electrical equipment. The total ARO liability as at December 31, 2015 has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating the companies' AROs represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the companies' current assumptions. The AROs may change from period to period because of changes in the estimation of these uncertainties. Other subsidiaries also affected by AROs associated with the removal of PCB-contaminated oil from electrical equipment include Central Hudson, FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. As at December 31, 2015, the AROs related to PCBs for the above-noted utilities were not material and, therefore, were not recognized.

Revenue Recognition: Revenue at the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator. Effective July 1, 2015, Central Hudson is permitted by the regulator to accrue unbilled revenue for electricity consumed at each period end for all of its electricity customers. As at December 31, 2014, approximately $15 million (US$13 million) in unbilled revenue at Central Hudson, associated with certain electricity customers, was not accrued, as permitted by the regulator.

The unbilled revenue accrual for the period is based on estimated electricity and gas sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the electricity and gas sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of electricity and gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity and gas consumption will result in adjustments of electricity and gas revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2015, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $404 million (December 31, 2014 – $365 million) on consolidated revenue of $6,727 million for 2015 (2014 – $5,401 million). The increase in accrued unbilled revenue from December 31, 2014 was primarily due to the impact of foreign exchange on the translation of US dollar-denominated unbilled revenue accruals.

Capitalized Overhead: As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recognized as operating expenses versus utility capital assets.

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

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

UNS Energy

Springerville Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") 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 ("New York Action") 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 ("AAA") 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 AAA 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 owner 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 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 at 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, the Company cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the 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.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company 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 is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset.

Central Hudson

Site Investigation and Remediation Program

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 DEC, 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 DEC 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 site investigation and 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 PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return. In the three-year rate order issued by the PSC in June 2015, Central Hudson's authorization to defer all site investigation and remediation costs was reaffirmed and extended through June 2018.

Asbestos Litigation

Prior to and after its acquisition by Fortis, various asbestos lawsuits have 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 the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding 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 the consolidated financial statements.

FortisBC Electric

The Government of British Columbia filed a claim in the British Columbia 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 consolidated financial statements.

FHI

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

RELATED-PARTY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related-party transactions for the years ended December 31, 2015 and 2014 are discussed below.

Upon completion of the Waneta Expansion in early April 2015, FortisBC Electric commenced purchasing capacity from the Waneta Expansion under terms of the 40-year WECA, as approved by the BCUC. Power purchased by FortisBC Electric from the Waneta Expansion in 2015 totalled approximately $30 million. In addition, the Waneta Expansion pays FortisBC Electric for management services associated with the generating station, which totalled approximately $7 million in 2015.

From time to time, the Corporation provides short-term financing to certain of its subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements, bearing interest at rates that approximate the Corporation's cost of short-term borrowing. In addition, the Corporation provided long-term financing to certain of its subsidiaries, bearing interest at rates that approximate the Corporation's cost of long-term debt. The majority of this long-term financing was repaid in 2015 as a result of the sale of commercial real estate and hotel assets. As at December 31, 2015, inter-segment loans outstanding totalled $48 million (December 31, 2014 – $402 million) and total interest charged in 2015 was $17 million (2014 – $27 million).

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2015, 2014 and 2013.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2015**	2014	2013
Revenue	**6,727**	5,401	4,047
Net earnings	**840**	390	420
Net earnings attributable to common equity shareholders	**728**	317	353
Basic earnings per common share	**2.61**	1.41	1.74
Diluted earnings per common share	**2.59**	1.40	1.73
Total assets	**28,804**	26,233	17,908
Long-term debt (excluding current portion)	**10,784**	9,911	6,424
Preference shares	**1,820**	1,820	1,229
Common shareholders' equity	**8,060**	6,871	4,772
Dividends declared per common share	**1.43**	1.30	1.25
Dividends declared per First Preference Share, Series C [(1)]	**–**	–	0.4862
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series F	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series G [(2)]	**0.9708**	0.9708	1.1416
Dividends declared per First Preference Share, Series H [(3)]	**0.7344**	1.0625	1.0625
Dividends declared per First Preference Share, Series I [(3)]	**0.3637**	–	–
Dividends declared per First Preference Share, Series J	**1.1875**	1.1875	1.1875
Dividends declared per First Preference Share, Series K [(4)]	**1.0000**	1.0000	0.6233
Dividends declared per First Preference Share, 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) On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020. The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate 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 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 and are entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years.

2015/2014: Revenue increased $1,326 million, or 24.6%, from 2014 and net earnings attributable to common equity shareholders were $728 million, or $2.61 per common share, compared to $317 million, or $1.41 per common share, in 2014. For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders, and earnings per common share, refer to the "Consolidated Results of Operations" and "Summary Financial Highlights" sections of this MD&A.

The growth in total assets reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets in 2015. The increase in long-term debt was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely to finance energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated long-term debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.

2014/2013: Revenue increased $1,354 million, or 33.5%, from 2013. The increase in revenue was driven by the acquisition of UNS Energy in August 2014 and Central Hudson in June 2013. A higher commodity cost of natural gas charged to customers at FortisBC Energy, an increase in the base component of rates at most of the regulated utilities and higher electricity sales also contributed to the increase in revenue.

Net earnings attributable to common equity shareholders were $317 million in 2014 compared to $353 million in 2013. Results for both years were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014 and Central Hudson in 2013. Earnings for 2014 were reduced by $39 million due to acquisition-related expenses and customer benefits offered to obtain regulatory approval of the acquisition of UNS Energy, compared to $34 million associated with the acquisition of Central Hudson in 2013. Interest expense of $51 million after tax, including the make-whole payment, associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy was recognized in 2014. In addition, earnings for 2013 were favourably impacted by an income tax recovery of $23 million due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends, an extraordinary gain of $20 million related to the settlement of expropriation matters associated with the Exploits River Hydro Partnership, and the release of income tax provisions of approximately $7 million. An $8 million foreign exchange gain was recognized in 2014 compared to $6 million in 2013. Earnings for 2014 included $5 million associated with Griffith to the date of sale, and earnings for 2013 were reduced by $5 million associated with Griffith.

Excluding the above-noted impacts, net earnings attributable to common equity shareholders for 2014 were $394 million, an increase of $58 million from $336 million for 2013. The increase was driven by $60 million of earnings contribution at UNS Energy from the date of acquisition and the first full year of earnings contribution from Central Hudson, which was acquired in June 2013. Rate base growth and an increase in the number of customers at FortisAlberta and electricity sales growth at Caribbean Regulated Electric Utilities also contributed to the increase. The increase was partially offset by lower earnings at FortisBC Electric, primarily due to the impact of lower-than-expected finance charges in 2013 and higher Corporate and Other expenses. The increase in Corporate and Other expenses was primarily due to higher finance charges, largely due to the acquisitions of UNS Energy and Central Hudson, and higher operating expenses, partially offset by a higher income tax recovery and interest income.

The growth in total assets reflects the Corporation's acquisition of UNS Energy in August 2014 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities in western Canada and the continued construction of the Waneta Expansion. The increase in long-term debt was primarily due to the financing of the acquisition of UNS Energy, including debt assumed on acquisition, and the financing of energy infrastructure investments.

Basic earnings per common share were $1.41 in 2014 compared to $1.74 in 2013. Excluding the above-noted non-recurring items in 2014 and 2013, basic earnings per common share were $1.75 for 2014, an increase of $0.09 from $1.66 for 2013. The increase was driven by accretion associated with the acquisition of UNS Energy.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2015 and 2014.

Summary of Gas Volumes and Electricity and Energy Sales

Fourth Quarters Ended December 31 *(Unaudited)*	**2015**	2014	Variance
Regulated Electric & Gas Utilities – United States			
UNS Energy – Electricity Sales *(GWh)*	**3,562**	3,583	(21)
UNS Energy – Gas Volumes *(PJ)*	**4**	4	–
Central Hudson – Electricity Sales *(GWh)*	**1,160**	1,176	(16)
Central Hudson – Gas Volumes *(PJ)*	**5**	5	–
Regulated Gas Utility – Canadian			
FortisBC Energy *(PJ)*	**62**	59	3
Regulated Electric Utilities – Canadian			
FortisAlberta *(GWh)*	**4,188**	4,446	(258)
FortisBC Electric *(GWh)*	**836**	846	(10)
Eastern Canadian *(GWh)*)	**2,189**	2,203	(14)
Regulated Electric Utilities – Caribbean *(GWh)*	**201**	187	14
Non-Regulated – Fortis Generation *(GWh)*	**122**	109	13

Gas Volumes

The increase in gas volumes at FortisBC Energy was mainly due to higher gas volumes for transportation customers due to certain customers switching to natural gas compared to alternative fuel sources.

Electricity and Energy Sales

The decrease in energy deliveries at FortisAlberta was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas. At most of the other regulated electric utilities, the decrease was mainly due to lower average consumption due to warmer temperatures, which reduced heating requirements. At the Regulated Electric Utilities – Caribbean, the impact of warmer temperatures increased electricity sales, due to higher air conditioning load. The overall decrease was partially offset by higher non-regulated energy sales, driven by the Waneta Expansion.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*	**Revenue**			**Net Earnings**		
($ millions, except per share amounts)	**2015**	2014	Variance	**2015**	2014	Variance
Regulated Electric & Gas Utilities – United States						
UNS Energy	**482**	435	47	**26**	23	3
Central Hudson	**202**	186	16	**15**	4	11
	684	621	63	**41**	27	14
Regulated Gas Utility – Canadian						
FortisBC Energy	**411**	432	(21)	**65**	49	16
Regulated Electric Utilities – Canadian						
FortisAlberta	**140**	132	8	**29**	25	4
FortisBC Electric	**99**	90	9	**8**	12	(4)
Eastern Canadian Electric Utilities	**273**	266	7	**15**	14	1
	512	488	24	**52**	51	1
Regulated Electric Utilities – Caribbean	**82**	84	(2)	**9**	6	3
Non-Regulated – Fortis Generation	**30**	8	22	**11**	4	7
Non-Regulated – Non-Utility	**6**	62	(56)	**1**	7	(6)
Corporate and Other	**2**	7	(5)	**(44)**	(31)	(13)
Inter-Segment Eliminations	**(19)**	(9)	(10)	**–**	–	–
Total	**1,708**	1,693	15	**135**	113	22
Basic Earnings per Common Share *($)*				**0.48**	0.44	0.04

Revenue

The increase in revenue was mainly due to favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion, and an increase in base electricity rates at the Canadian Regulated Electric Utilities. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets.

Earnings

The increase in earnings was primarily due to: (i) favourable foreign exchange impacts; (ii) an increase in base electricity rates at Central Hudson effective July 1, 2015, combined with the impact of storm restoration and other non-recurring expenses recognized in the fourth quarter of 2014; (iii) earnings contribution of approximately $6 million from the Waneta Expansion; (iv) rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta; and (v) a higher AFUDC at FortisBC Energy, partially offset by higher operating expenses. The timing of regulatory deferral mechanisms had a favourable impact on FortisBC Energy's earnings for the quarter and an unfavourable impact on FortisBC Electric. The increase in earnings was partially offset by lower earnings contribution due to the sale of commercial real estate and hotel assets and higher Corporate and Other expenses. Corporate and Other expenses included $7 million in acquisition-related expenses in the fourth quarter of 2015 and in the fourth quarter of 2014 included $4 million in interest expense associated with the convertible debentures and a $3 million foreign exchange gain. Excluding these items, the increase in Corporate and Other expenses was mainly due to a lower income tax recovery and lower related-party interest income.

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2015**	2014	Variance
Cash, Beginning of Period	**347**	458	(111)
Cash Provided by (Used in):			
Operating Activities	**397**	334	63
Investing Activities	**(234)**	(829)	595
Financing Activities	**(280)**	257	(537)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**12**	10	2
Cash, End of Period	**242**	230	12

Cash flow from operating activities was $63 million higher quarter over quarter. The increase was primarily due to higher cash earnings at the Corporation's regulated utilities.

Cash used in investing activities was $595 million lower quarter over quarter. The decrease was mainly due to lower capital expenditures at the regulated utilities, largely due to UNS Energy's purchase of Gila River Unit 3 generation station in December 2014 for approximately $252 million (US$219 million), and proceeds received from the sale of hotel assets in October 2015 for $365 million.

Cash provided by financing activities was $537 million lower quarter over quarter. The decrease was primarily due to the repayment of credit facility borrowings in the fourth quarter of 2015 using proceeds from the sale of hotel assets. In addition, lower proceeds from long-term debt and lower credit facility borrowings were partially offset by lower repayments of long-term debt. In the fourth quarter of 2014, proceeds from the second installment of the convertible debentures were received, which were used to repay acquisition credit facilities used initially to finance a portion of the acquisition of UNS Energy.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2014 through December 31, 2015. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results
(Unaudited)

Quarter Ended	Revenue ($ millions)	Net Earnings Attributable to Common Equity Shareholders ($ millions)	Earnings per Common Share Basic ($)	Earnings per Common Share Diluted ($)
December 31, 2015	1,708	135	0.48	0.48
September 30, 2015	1,566	151	0.54	0.54
June 30, 2015	1,538	244	0.88	0.87
March 31, 2015	1,915	198	0.72	0.71
December 31, 2014	1,693	113	0.44	0.43
September 30, 2014	1,197	14	0.06	0.06
June 30, 2014	1,056	47	0.22	0.22
March 31, 2014	1,455	143	0.67	0.66

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions and associated acquisition-related expenses, and the impact of sale transactions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity and gas demand in different regions, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of FortisBC Energy are realized in the first and fourth quarters. 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.

December 2015/December 2014: Net earnings attributable to common equity shareholders were $135 million, or $0.48 per common share, for the fourth quarter of 2015 compared to earnings of $113 million, or $0.44 per common share, for the fourth quarter of 2014. A discussion of the variances in financial results for the fourth quarter of 2015 and the fourth quarter of 2014 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2015/September 2014: Net earnings attributable to common equity shareholders were $151 million, or $0.54 per common share, for the third quarter of 2015 compared to earnings of $14 million, or $0.06 per common share, for the third quarter of 2014. Earnings for the third quarter of 2015 were favourably impacted by a $5 million gain on the sale of non-regulated generation assets in Ontario and a $5 million positive adjustment associated with the sale of hotel assets, and were reduced by a $9 million loss on the settlement of expropriation matters related to the Corporation's investment in Belize Electricity. Earnings for the third quarter of 2014 were reduced by a total of $58 million due to acquisition-related expenses associated with UNS Energy. Excluding these items, the increase in earnings was driven by contribution of $97 million at UNS Energy compared to $37 million for the third quarter of 2014. Earnings contribution of $5 million from the Waneta Expansion also contributed to the increase. Performance was also driven by the Corporation's other regulated utilities, including rate base growth associated with capital expenditures and customer growth at FortisAlberta; improved performance at Central Hudson; and favourable foreign exchange associated with US dollar-denominated earnings. Earnings at FortisBC Energy and FortisBC Electric were impacted by the timing of regulatory deferral mechanisms; however, FortisBC Energy's earnings were favourably impacted by lower operating expenses and higher AFUDC. The increase was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy.

June 2015/June 2014: Net earnings attributable to common equity shareholders were $244 million, or $0.88 per common share, for the second quarter of 2015 compared to earnings of $47 million, or $0.22 per common share, for the second quarter of 2014. The increase was driven by a net gain of $123 million on the sale of commercial real estate, hotel and non-regulated generation assets. The increase was also due to earnings contribution of $52 million at UNS Energy and $12 million from the Waneta Expansion, representing the Corporation's 51% controlling ownership. Performance was also driven by the Corporation's regulated utilities, including rate base growth associated with capital expenditures, customer growth and a decrease in depreciation and amortization at FortisAlberta; increases at FortisBC Electric, largely due to timing of quarterly earnings compared to the same period last year, resulting from the impact of regulatory deferral mechanisms; and improved performance at Central Hudson. The increase was partially offset by a $5 million decrease in earnings at FortisBC Energy due to the timing of regulatory flow-through deferral amounts, and higher preference share dividends and finance charges in the Corporate and Other segment associated with the acquisition of UNS Energy.

March 2015/March 2014: Net earnings attributable to common equity shareholders were $198 million, or $0.72 per common share, for the first quarter of 2015 compared to earnings of $143 million, or $0.67 per common share, for the first quarter of 2014. The increase in earnings was driven by the Corporation's regulated utilities. UNS Energy contributed earnings of $20 million in the first quarter of 2015. FortisAlberta's earnings were favourably impacted by higher capital tracker revenue, including approximately $10 million associated with 2013 and 2014, and customer growth. Earnings at FortisBC Energy and FortisBC Electric were $9 million and $5 million, respectively, higher quarter over quarter, largely due to timing of quarterly earnings compared to the same period last year resulting from the impact of regulatory deferral mechanisms. Central Hudson and Eastern Canadian Regulated Electric Utilities also reported improved performance. The increase in earnings at the regulated utilities was partially offset by lower earnings at the Corporation's non-regulated subsidiaries, largely due to decreased production in Belize as a result of lower rainfall, costs at Fortis Properties associated with the strategic review, and approximately $5 million earnings contribution in the first quarter of 2014 from Griffith to the date of sale. Corporate and Other expenses were lower quarter over quarter, due to approximately $11 million in after-tax interest expense associated with the convertible debentures in the first quarter of 2014 and a higher foreign exchange gain, partially offset by higher preference share dividends and finance charges associated with the acquisition of UNS Energy.

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

Disclosure Controls and Procedures: The President and Chief Executive Officer ("CEO") and the Executive Vice President, Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2015 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting: The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with US GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2015 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2015, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

SUBSEQUENT EVENT

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 Improvements 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, and 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.

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.

OUTSTANDING SHARE DATA

As at February 16, 2016, the Corporation had issued and outstanding 281.9 million common shares; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M. Only the common shares of the Corporation have voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options and First Preference Shares, Series E were converted as at February 16, 2016 is as follows.

Conversion of Securities into Common Shares

As at February 16, 2016 *(Unaudited)*

Security	Number of Common Shares *(millions)*
Stock Options	**4.9**
First Preference Shares, Series E	**5.8**
Total	**10.7**

Additional information, including the Fortis 2015 Annual Information Form, Management Information Circular and Audited Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

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MANAGEMENT'S REPORT

The accompanying Annual Consolidated Financial Statements of Fortis Inc. have been prepared by management, who is responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2015 Annual Consolidated Financial Statements were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2015 Annual Consolidated Financial Statements and their report follows.

Barry Perry

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

Karl Smith

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

St. John's, Canada

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheets as at December 31, 2015 and 2014, and the consolidated statements of earnings, comprehensive income, cash flows and changes in equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

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

Auditors' responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion
In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2015 and 2014, and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States.

Ernst & Young LLP

St. John's, Canada
February 17, 2016

Chartered Professional Accountants

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)

ASSETS	2015	2014
Current assets		*(Note 36)*
Cash and cash equivalents	**$ 242**	$ 230
Accounts receivable and other current assets *(Note 6)*	**964**	900
Prepaid expenses	**68**	59
Inventories *(Note 7)*	**337**	321
Regulatory assets *(Note 8)*	**246**	277
	1,857	1,787
Other assets *(Note 9)*	**352**	272
Regulatory assets *(Note 8)*	**2,286**	2,138
Utility capital assets *(Note 10)*	**19,595**	17,179
Non-utility capital assets *(Note 11)*	**–**	664
Intangible assets *(Note 12)*	**541**	461
Goodwill *(Note 13)*	**4,173**	3,732
	$ 28,804	$ 26,233
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 32)*	**$ 511**	$ 330
Accounts payable and other current liabilities *(Note 14)*	**1,419**	1,440
Regulatory liabilities *(Note 8)*	**298**	173
Current installments of long-term debt *(Note 15)*	**384**	525
Current installments of capital lease and finance obligations *(Note 16)*	**26**	208
	2,638	2,676
Other liabilities *(Note 17)*	**1,152**	1,141
Regulatory liabilities *(Note 8)*	**1,340**	1,272
Deferred income taxes *(Note 26)*	**2,050**	1,626
Long-term debt *(Note 15)*	**10,784**	9,911
Capital lease and finance obligations *(Note 16)*	**487**	495
	18,451	17,121
Shareholders' equity		
Common shares [(1)] *(Note 18)*	**5,867**	5,667
Preference shares *(Note 20)*	**1,820**	1,820
Additional paid-in capital	**14**	15
Accumulated other comprehensive income *(Note 21)*	**791**	129
Retained earnings	**1,388**	1,060
	9,880	8,691
Non-controlling interests *(Note 22)*	**473**	421
	10,353	9,112
	$ 28,804	$ 26,233

[(1)] No par value. Unlimited authorized shares; 281.6 million and 276.0 million issued and outstanding as at December 31, 2015 and 2014, respectively

Commitments *(Note 33)*
Contingencies *(Note 34)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

David G. Norris,
Director

Peter E. Case,
Director

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2015**	2014
Revenue	**$ 6,727**	$ 5,401
Expenses		
Energy supply costs	**2,561**	2,197
Operating	**1,864**	1,493
Depreciation and amortization	**873**	688
	5,298	4,378
Operating income	**1,429**	1,023
Other income (expenses), net *(Note 24)*	**187**	(25)
Finance charges *(Note 25)*	**553**	547
Earnings before income taxes and discontinued operations	**1,063**	451
Income tax expense *(Note 26)*	**223**	66
Earnings from continuing operations	**840**	385
Earnings from discontinued operations, net of tax *(Note 28)*	**–**	5
Net earnings	**$ 840**	$ 390
Net earnings attributable to:		
Non-controlling interests	**$ 35**	$ 11
Preference equity shareholders	**77**	62
Common equity shareholders	**728**	317
	$ 840	$ 390
Earnings per common share from continuing operations *(Note 19)*		
Basic	**$ 2.61**	$ 1.39
Diluted	**$ 2.59**	$ 1.38
Earnings per common share *(Note 19)*		
Basic	**$ 2.61**	$ 1.41
Diluted	**$ 2.59**	$ 1.40

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2015**	2014
Net earnings	**$ 840**	$ 390
Other comprehensive income (loss)		
Unrealized foreign currency translation gains, net of hedging activities and tax *(Note 21)*	**660**	204
Reclassification to earnings of foreign currency translation loss on disposal of investment in foreign operations, net of tax *(Note 21)*	**2**	–
Net change in fair value of cash flow hedges, net of tax *(Notes 21 and 31)*	**1**	1
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax *(Note 21)*	**–**	1
Unrealized loss on available-for-sale investment, net of tax *(Notes 9, 21 and 31)*	**(2)**	–
Unrealized employee future benefits gains (losses), net of tax *(Notes 21 and 27)*	**1**	(5)
	662	201
Comprehensive income	**$ 1,502**	$ 591
Comprehensive income attributable to:		
Non-controlling interests	**$ 35**	$ 11
Preference equity shareholders	**77**	62
Common equity shareholders	**1,390**	518
	$ 1,502	$ 591

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2015**	2014
Operating activities		
Net earnings	**$ 840**	$ 390
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – capital assets	**785**	597
Amortization – intangible assets	**64**	60
Amortization – other	**24**	31
Deferred income tax expense *(Note 26)*	**164**	23
Accrued employee future benefits	**(19)**	25
Equity component of allowance for funds used during construction *(Note 24)*	**(23)**	(11)
Gain on sale of non-utility capital assets *(Note 24)*	**(131)**	–
Gain on sale of non-regulated generation assets *(Note 24)*	**(62)**	–
Other	**79**	71
Change in long-term regulatory assets and liabilities	**(89)**	(80)
Change in non-cash operating working capital *(Note 30)*	**41**	(124)
	1,673	982
Investing activities		
Change in other assets and other liabilities	**(36)**	(4)
Capital expenditures – utility capital assets	**(2,122)**	(1,617)
Capital expenditures – non-utility capital assets	**(9)**	(39)
Capital expenditures – intangible assets	**(112)**	(69)
Contributions in aid of construction	**59**	69
Purchase of assets held for sale *(Notes 6 and 16)*	**(32)**	–
Proceeds on sale of assets *(Notes 16 and 28)*	**922**	109
Business acquisitions, net of cash acquired *(Notes 9 and 29)*	**(38)**	(2,648)
	(1,368)	(4,199)
Financing activities		
Change in short-term borrowings	**148**	167
Proceeds from convertible debentures, net of issue costs *(Note 18)*	**–**	1,725
Proceeds from long-term debt, net of issue costs *(Note 15)*	**1,002**	1,193
Repayments of long-term debt and capital lease and finance obligations	**(602)**	(743)
Net (repayments) borrowings under committed credit facilities	**(622)**	610
Advances from non-controlling interests	**20**	38
Issue of common shares, net of costs and dividends reinvested *(Note 18)*	**40**	51
Issue of preference shares, net of costs *(Note 20)*	**–**	586
Dividends		
Common shares, net of dividends reinvested	**(232)**	(194)
Preference shares	**(77)**	(62)
Subsidiary dividends paid to non-controlling interests	**(23)**	(10)
	(346)	3,361
Effect of exchange rate changes on cash and cash equivalents	**53**	14
Change in cash and cash equivalents	**12**	158
Cash and cash equivalents, beginning of year	**230**	72
Cash and cash equivalents, end of year	**$ 242**	$ 230

Supplementary Information to Consolidated Statements of Cash Flows *(Note 30)*

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31, 2015 and 2014 (in millions of Canadian dollars)	**Common Shares**	**Preference Shares**	**Additional Paid-in Capital**	**Accumulated Other Comprehensive Income (Loss)**	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
	(Note 18)	*(Note 20)*		*(Note 21)*		*(Note 22)*	
As at January 1, 2015	**$ 5,667**	**$ 1,820**	**$ 15**	**$ 129**	**$ 1,060**	**$ 421**	**$ 9,112**
Net earnings	**–**	**–**	**–**	**–**	**805**	**35**	**840**
Other comprehensive income	**–**	**–**	**–**	**662**	**–**	**–**	**662**
Common share issues	**200**	**–**	**(4)**	**–**	**–**	**–**	**196**
Stock-based compensation	**–**	**–**	**3**	**–**	**–**	**–**	**3**
Advances from non-controlling interests	**–**	**–**	**–**	**–**	**–**	**20**	**20**
Foreign currency translation impacts	**–**	**–**	**–**	**–**	**–**	**20**	**20**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**(23)**	**(23)**
Dividends declared on common shares ($1.43 per share)	**–**	**–**	**–**	**–**	**(400)**	**–**	**(400)**
Dividends declared on preference shares	**–**	**–**	**–**	**–**	**(77)**	**–**	**(77)**
As at December 31, 2015	**$ 5,867**	**$ 1,820**	**$ 14**	**$ 791**	**$ 1,388**	**$ 473**	**$ 10,353**
As at January 1, 2014	$ 3,783	$ 1,229	$ 17	$ (72)	$ 1,044	$ 375	$ 6,376
Net earnings	–	–	–	–	379	11	390
Other comprehensive income	–	–	–	201	–	–	201
Preference share issue	–	591	–	–	–	–	591
Common share issues	1,884	–	(5)	–	–	–	1,879
Stock-based compensation	–	–	3	–	–	–	3
Advances from non-controlling interests	–	–	–	–	–	38	38
Foreign currency translation impacts	–	–	–	–	–	7	7
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	(10)	(10)
Dividends declared on common shares ($1.30 per share)	–	–	–	–	(301)	–	(301)
Dividends declared on preference shares	–	–	–	–	(62)	–	(62)
As at December 31, 2014	$ 5,667	$ 1,820	$ 15	$ 129	$ 1,060	$ 421	$ 9,112

See accompanying Notes to Consolidated Financial Statements

For the years ended December 31, 2015 and 2014

1. DESCRIPTION OF THE BUSINESS

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international 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 are treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

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

Regulated Utilities

The Corporation's interests in regulated electric and gas utilities are as follows.

Regulated Electric & Gas Utilities – United States

a. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively, the "UNS Utilities"), acquired by Fortis in August 2014 (Note 29).

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.

   UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to retail customers in Arizona's Mohave and Santa Cruz counties.

   TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,799 megawatts ("MW"), including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2015, approximately 43% of the generating capacity was fuelled by coal.

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

b. *Central Hudson:* Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Regulated Gas Utility – Canadian

FortisBC Energy: Primarily includes FortisBC Energy Inc. ("FortisBC Energy" or "FEI") and, prior to December 31, 2014, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company (Note 2). FEI is the largest distributor of natural gas in British Columbia, serving more than 135 communities. Major areas served by the Company are the Lower Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

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

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro; the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("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.

For the years ended December 31, 2015 and 2014

1. DESCRIPTION OF THE BUSINESS (cont'd)

Regulated Electric Utilities – Canadian (cont'd)

c. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("FortisOntario"). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"). Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are primarily comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power").

Regulated Electric Utilities – Caribbean

The Regulated Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2014 – 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity") (Note 9). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed diesel-powered generating capacity of 132 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities that provide electricity to certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated – Fortis Generation

Fortis Generation is primarily comprised of long-term contracted generation assets in British Columbia and Belize. Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion. Construction of the Waneta Expansion was completed in April 2015 and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts. The Corporation's 51% controlling ownership interest in the Waneta Expansion is conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest.

Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

As at December 31, 2015, the 16-MW run-of-river Walden hydroelectric generating facility ("Walden") has been classified as held for sale (Note 6).

In June 2015 and July 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario, respectively (Notes 24 and 28).

Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties") and Griffith Energy Services, Inc. ("Griffith"). Fortis Properties completed the sale of its commercial real estate assets in June 2015 and its hotel assets in October 2015, and Griffith was sold in March 2014 (Note 28).

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments.

The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. ("CH Energy Group") and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

2. NATURE OF REGULATION

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

When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of the actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8).

The nature of regulation at the Corporation's utilities is as follows.

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

TEP's allowed ROE is set at 10.0% on a capital structure of 43.5% common equity, effective from July 1, 2013. UNS Electric's allowed ROE is set at 9.50% on a capital structure of 52.6% common equity, effective from January 1, 2014. UNS Gas' allowed ROE is set at 9.75% on a capital structure of 50.8% common equity, effective from May 1, 2012.

Central Hudson
Central Hudson is regulated by the New York State Public Service Commission ("PSC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). The Company is also subject to regulation by the North American Electric Reliability Corporation. Central Hudson operates under COS regulation as administered by the PSC with the use of a future test year in the establishment of rates.

Central Hudson began operating under a three-year rate order issued by the PSC effective July 1, 2010 with an allowed ROE set at 10.0% on a deemed capital structure of 48% common equity. As approved by the PSC in June 2013, the original three-year rate order was extended for two years, through June 30, 2015, as part of the regulatory approval of the acquisition of Central Hudson by Fortis. In June 2015 the PSC issued a rate order for the Company covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. The new rate order reflects an allowed ROE of 9.0% and a 48% common equity component of capital structure.

Effective July 1, 2013, Central Hudson was also subject to an earnings sharing mechanism, whereby the Company and customers share equally earnings in excess of the allowed ROE up to an achieved ROE that is 50 basis points above the allowed ROE, and share 10%/90% (Company/customers) earnings in excess of 50 basis points above the allowed ROE. In the new rate order effective July 1, 2015, the earnings sharing mechanism was continued, whereby the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer.

FortisBC Energy and FortisBC Electric
FortisBC Energy and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC") pursuant to the *Utilities Commission Act* (British Columbia). The Companies primarily operate under COS regulation and, from time to time, PBR mechanisms for establishing customer rates.

2. NATURE OF REGULATION (cont'd)

FortisBC Energy and FortisBC Electric (cont'd)

In the first stage of the Generic Cost of Capital ("GCOC") Proceeding in British Columbia, FEI was designated as the benchmark utility and a BCUC decision established that the allowed ROE for the benchmark utility would be set at 8.75% on a 38.5% common equity component of capital structure, both effective January 1, 2013 through December 31, 2015. In March 2014 the BCUC issued its decision on the second stage of the GCOC Proceeding, setting the common equity component of capital structure for FEVI and FEWI at 41.5%, and reaffirming the common equity component of capital structure for FortisBC Electric at 40%, all effective January 1, 2013. The resulting allowed ROEs for FEVI, FEWI and FortisBC Electric were 9.25%, 9.50% and 9.15%, respectively, also effective January 1, 2013. Effective January 1, 2015, following the amalgamation of FEI, FEVI and FEWI, the ROE and common equity component of capital structure for the amalgamated FEI, was set to equal the benchmark utility, at 8.75% and 38.5%, respectively.

FEI and FortisBC Electric are subject to Multi-Year PBR Plans for 2014 through 2019. The PBR Plans, as approved by the BCUC, incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FEI and 1.03% for FortisBC Electric each year. The approved PBR Plans also include a 50%/50% sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI and FortisBC Electric maintain service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between the utilities and interested parties regarding current performance and future activities.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). Effective January 1, 2013, the AUC prescribed that distribution utilities in Alberta, including FortisAlberta, move to PBR for a five-year term. Under PBR, each year the prescribed formula is applied to the preceding year's distribution rates, with 2012 used as the going-in distribution rates.

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

The funding of capital expenditures during the PBR term is a material aspect of the PBR plan for FortisAlberta. The PBR plan provides a capital tracker mechanism to fund the recovery of costs associated with certain qualifying capital expenditures. In March 2015 the AUC issued its decision related to FortisAlberta's 2013, 2014 and 2015 Capital Tracker Applications. The decision: (i) indicated that the majority of the Company's applied for capital trackers met the established criteria and were, therefore, approved for collection from customers; (ii) approved FortisAlberta's accounting test to determine qualifying K factor amounts; and (iii) confirmed certain inputs to be used in the accounting test, including the conclusion that the weighted average cost of capital be based on actual debt rates and the allowed ROE and capital structure approved in the GCOC Proceeding.

In September 2015 the AUC approved FortisAlberta's compliance filing related to the 2015 Capital Tracker Decision, substantially as filed. Capital tracker revenue of $17 million was approved for 2013 on an actual basis and capital tracker revenue of $42 million and $62 million was approved on a forecast basis for 2014 and 2015, respectively. FortisAlberta collected $15 million, $29 million and $62 million in 2013, 2014 and 2015, respectively, related to capital tracker expenditures.

FortisAlberta recognized capital tracker revenue of approximately $59 million in 2015, of which $9 million was related to updates to the 2013 and 2014 capital tracker approved amounts. The capital tracker revenue for 2015 of approximately $50 million incorporates an update for related 2015 capital tracker expenditures as compared to the approved forecast reflected in current rates. This resulted in a deferral of $12 million of 2015 capital tracker revenue as a regulatory liability.

In March 2015 the AUC issued its decision on the GCOC Proceeding in Alberta. The GCOC Proceeding set FortisAlberta's allowed ROE for 2013 through 2015 at 8.30%, down from the interim allowed ROE of 8.75%, and set the common equity component of capital structure at 40%, down from 41%. The AUC also determined that it would not re-establish a formula-based approach to setting the allowed ROE at this time. Instead, the allowed ROE of 8.30% and common equity component of capital structure of 40% will remain in effect on an interim basis for 2016 and beyond. For regulated utilities in Alberta under PBR mechanisms, including FortisAlberta, the impact of the changes to the allowed ROE and common equity component of capital structure resulting from the GCOC Proceeding applies to the portion of rate base that is funded by capital tracker revenue only. For assets not being funded by capital tracker revenue, no revenue adjustment is required for the change in the allowed ROE and common equity component of capital structure, from that set in an earlier GCOC decision.

Eastern Canadian Electric Utilities

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). Newfoundland Power operates under COS regulation with the use of a future test year in the establishment of rates. The PUB has set the allowed ROE at 8.80% and the common equity component of capital structure at 45% for 2013 through 2015.

Maritime Electric is regulated by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI), the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), and the *Electric Power (Energy Accord Continuation) Amendment Act* (PEI) ("Accord Continuation Act"), which covers the period March 1, 2013 to February 29, 2016. Maritime Electric operates under COS regulation with the use of a future test year for the establishment of rates. IRAC set the allowed ROE at 9.75% on a targeted minimum capital structure of 40% common equity for 2014 and 2015.

In Ontario, Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under COS regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Fourth-Generation Incentive Regulation Mechanism as prescribed by the OEB. Algoma Power is also subject to the use and implementation of the Rural and Remote Rate Protection ("RRRP") Program. The RRRP Program is calculated as the deficiency between the approved revenue requirement from the OEB and current customer electricity distribution rates, adjusted for the average rate increase across the province of Ontario. Canadian Niagara Power and Algoma Power use a future test year in the establishment of rates. Canadian Niagara Power's allowed ROE for distribution assets was set at 8.93% for 2014 and 2015 and the allowed ROE for transmission assets was set at 8.93% for 2014 and 9.30% for 2015, both on a deemed capital structure of 40% common equity. Algoma Power's allowed ROE was set at 9.85% for 2014 and 9.30% for 2015 on a deemed capital structure of 40% common equity. Cornwall Electric is subject to a rate-setting mechanism under a 35-year Franchise Agreement with the City of Cornwall expiring in 2033 and, therefore, is exempt from many aspects of the above Acts. The rate-setting mechanism is based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Regulated Electric Utilities – Caribbean

Caribbean Utilities operates under T&D and generation licences from the Government of the Cayman Islands. The exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. In November 2014 a new non-exclusive generation licence was issued for a term of 25 years, expiring in November 2039. The licences detail the role of the Electricity Regulatory Authority, which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism ("RCAM"), and annually approves capital expenditures. The licences contain the provision for an RCAM based on published consumer price indices. Caribbean Utilities' targeted allowed ROA for 2015 was in the range of 7.25% to 9.25%, compared to a range of 7.00% to 9.00% for 2014.

Fortis Turks and Caicos operates under two 50-year licences expiring in 2036 and 2037. Among other matters, the licences describe how electricity rates are set by the Government of the Turks and Caicos Islands, using a historical test year, in order to provide the utilities with an allowed ROA of between 15.0% and 17.5% (the "Allowable Operating Profit"). The Allowable Operating Profit is based on a calculated rate base including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall"). Annual submissions are made to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2015 calculated the Allowable Operating Profit to be $51 million (US$40 million) and the Cumulative Shortfall as at December 31, 2015 to be $274 million (US$198 million). The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses. The achieved ROAs at the utilities have been significantly lower than those allowed under the licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

All amounts presented are in Canadian dollars unless otherwise stated.

Basis of Presentation

The consolidated financial statements reflect the Corporation's investments in its subsidiaries on a consolidated basis, with the equity method used for entities in which Fortis has significant influence, but not control, and proportionate consolidation for generation and transmission assets that are jointly owned with non-affiliated entities. All material intercompany transactions have been eliminated in the consolidated financial statements.

An evaluation of subsequent events through to February 17, 2016, the date these consolidated financial statements were approved by the Board of Directors of Fortis ("Board of Directors"), was completed to determine whether the circumstances warranted recognition and disclosure of events or transactions in the consolidated financial statements as at December 31, 2015 (Note 35).

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of uncollectible accounts receivable balances. Fortis and each of its subsidiaries maintain an allowance for doubtful accounts that is estimated based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy and economic conditions. Interest is charged on accounts receivable balances that have been outstanding for more than 21 to 30 days. Accounts receivable are written-off in the period in which the receivable is deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and market value, unless evidence indicates that the weighted average cost, even in excess of market, will be recovered in future customer rates.

Regulatory Assets and Liabilities

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

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

Investments

Portfolio investments are accounted for on the cost basis. Declines in value considered to be other than temporary are recorded in the period in which such determinations are made. Investments in which the Corporation exercises significant influence are accounted for on the equity basis. The Corporation reviews its investments on an annual basis for potential impairment in investment value. Should an impairment be identified, it will be recognized in the period in which such impairment is identified.

Available-for-Sale Assets

The Corporation's assets designated as available-for-sale are measured at fair value based on quoted market prices. Unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold.

Utility Capital Assets

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

Each of UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-asset retirement obligations ("AROs") removal costs in depreciation, as required by their respective regulator, with the amount provided for in depreciation recorded as a long-term regulatory liability (Note 8 *(xiv)*). Actual non-ARO removal costs are recorded against the regulatory liability when incurred. As permitted by the regulator, FortisBC Electric records actual non-ARO removal costs, net of salvage proceeds, against accumulated depreciation as incurred. FortisOntario, Fortis Turks and Caicos and Waneta Expansion recognize non-ARO removal costs, net of salvage proceeds, in earnings in the period incurred. Caribbean Utilities recognizes non-ARO removal costs in utility capital assets.

Utility capital assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of utility capital assets, any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation by UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gains or losses charged to accumulated depreciation will be reflected in future depreciation expense when they are refunded or collected in customer electricity and gas rates. At FortisOntario, as required by its regulator, and the Waneta Partnership, any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets is recognized immediately in earnings.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities include in the cost of utility capital assets both a debt and an equity component of the allowance for funds used during construction ("AFUDC"). The debt component of AFUDC is reported as a reduction of finance charges (Note 25) and the equity component of AFUDC is reported as other income (Note 24). Both components of AFUDC are charged to earnings through depreciation expense over the estimated service lives of the applicable utility capital assets. AFUDC is calculated in a manner as prescribed by the respective regulator.

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

As approved by the regulator, FortisBC Energy has reduced the amounts reported for utility capital assets by the amount of government loans received in connection with the construction and operation of the Vancouver Island natural gas pipeline. As the loans are repaid and replaced with non-government loans, FortisBC Energy increases both utility capital assets and long-term debt (Note 15).

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets, with the exception of UNS Energy. As required by its regulator, UNS Energy recognizes inventories held for the development and construction of other utility capital assets in inventories until consumed. When put into service, the inventories are reclassified to utility capital assets (Note 7).

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred, while replacements and betterments which extend the useful lives are capitalized.

Utility capital assets are depreciated using the straight-line method based on the estimated service lives of the utility capital assets. Depreciation rates for regulated utility capital assets are approved by the respective regulator. Depreciation rates for 2015 ranged from 1.3% to 43.2% (2014 – 1.3% to 43.2%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, for 2015 was 3.1% (2014 – 3.2%).

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

Utility Capital Assets (cont'd)

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

	2015		2014	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5–80**	**30**	5–80	28
Gas	**4–95**	**33**	4–85	31
Transmission				
Electric	**20–80**	**29**	20–70	27
Gas	**7–80**	**36**	4–71	38
Generation	**5–85**	**27**	4–75	24
Other	**3–70**	**8**	3–70	8

Non-Utility Capital Assets

In 2015 the Corporation sold its commercial real estate and hotel assets, which included office buildings, shopping malls, hotels, land, construction in progress, and related equipment and tenant inducements (Note 28). Non-utility capital assets were recorded at cost less accumulated depreciation, where applicable, using the straight-line method of depreciation.

Maintenance and repairs were charged to earnings in the period incurred, while replacements and betterments which extended the useful lives were capitalized.

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Included as capital leases are any arrangements that qualify as leases by conveying the right to use a specific asset.

Capital leases are depreciated over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case capital leases are depreciated over the estimated service life of the underlying asset. Where the regulator has approved recovery of the arrangements as operating leases for rate-setting purposes that would otherwise qualify as capital leases for financial reporting purposes, the timing of the expense recognition related to the lease is modified to conform with the rate-setting process.

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

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Intangible assets are comprised of computer software costs; land, transmission and water rights; and franchise fees. The cost of intangible assets at the Corporation's regulated subsidiaries includes amounts for AFUDC and allocated overhead, where permitted by the respective regulators. Costs incurred to renew or extend the term of an intangible asset are capitalized and amortized over the new term of the intangible asset.

The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually, either individually or at the reporting unit level, if they are held in a regulated utility. Such intangible assets are not amortized. Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights at UNS Energy, FortisBC Energy, FortisBC Electric and the Waneta Partnership. An intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

In testing indefinite-lived intangible assets for impairment, the Corporation has the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50% or more likely to be greater than the carrying value, calculation of fair value would not be required.

Impairment testing for indefinite-lived intangible assets is carried out at the reporting unit level at the regulated utilities. A fair rate of return on the indefinite-lived intangible assets is provided through customer electricity and gas rates, as approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of the indefinite-lived intangible assets is below its carrying value. No such event or change in circumstances occurred during 2015 or 2014 and there were no impairment provisions required in either year. For its annual testing of impairment for indefinite-lived intangible assets, Fortis uses the approach for the annual testing for goodwill impairment as disclosed in this Note under "Goodwill".

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets and are assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the respective regulator.

Amortization rates for 2015 ranged from 1.0% to 50.0% (2014 – 1.0% to 50.0%). The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows:

	2015		2014	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3–10**	**4**	3–10	4
Land, transmission and water rights	**30–80**	**37**	30–75	32
Franchise fees and other	**10–104**	**15**	10–100	19

Intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization by UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gains or losses charged to accumulated amortization will be reflected in future amortization costs when they are refunded or collected in customer electricity and gas rates. At FortisOntario, as required by its regulator, and the Waneta Partnership, any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets is recognized immediately in earnings.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no material impact on the consolidated financial statements as a result of regulated long-lived asset or non-regulated generation asset impairments for the years ended December 31, 2015 and 2014. Certain of the Corporation's non-utility hotel assets, all of which were sold in 2015, were subject to an impairment charge as a result of the carrying amount of the assets exceeding their fair value (Note 28).

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

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash flow stream, such an asset is tested individually and impairment is recorded if the future net cash flows are no longer sufficient to recover the carrying value of the generating facility.

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

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

Fortis performs an annual internal quantitative assessment for each reporting unit. For those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) where the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit is below its carrying value. No such event or change in circumstances occurred during 2015 or 2014 and no impairment provisions were required in either year.

In calculating goodwill impairment, Fortis determines those reporting units that will have fair value estimated by an external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, may also be performed by an external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

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

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

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

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

With the exception of UNS Energy, FortisAlberta and Maritime Electric, any difference between pension cost recognized under US GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*). As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made.

At UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8 *(ii)*). At Fortis, FHI and Caribbean Utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans are recognized in accumulated other comprehensive income.

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

Other Post-Employment Benefits Plans

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

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

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

As approved by the regulator, the cost of OPEB plans at FortisAlberta is recovered in customer rates based on the cash payments made.

With the exception of UNS Energy and FortisAlberta, any difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*).

At FortisAlberta, the difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates does not meet the criteria for deferral account treatment and, therefore, FortisAlberta recognizes in earnings the cost associated with its OPEB plan as actuarially determined, rather than as approved by the regulator. Unamortized OPEB plan balances at FortisAlberta related to net actuarial gains and losses and past service costs are recognized as a component of other comprehensive income.

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its 2002 Stock Option Plan ("2002 Plan"), 2006 Stock Option Plan ("2006 Plan") and 2012 Stock Option Plan ("2012 Plan") (Note 23). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and each grant is amortized as a single award evenly over the four-year vesting period of the options granted. The offsetting entry is an increase to additional paid-in capital for an amount equal to the annual compensation expense related to the issuance of stock options. The stock options become exercisable once time vesting requirements have been met. Upon exercise, the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock. An exercise of options below the current market price of the Corporation's common shares has a dilutive effect on the Corporation's consolidated capital stock and shareholders' equity. Fortis satisfies stock option exercises by issuing common shares from treasury.

The Corporation also records liabilities associated with its Directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans, all representing cash settled awards, at fair value at each reporting date until settlement. Compensation expense is recognized on a straight-line basis over the vesting period, which, for the PSU and RSU Plans, is over the shorter of three years or the period to retirement eligibility. The fair value of the DSU, PSU and RSU liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP of the Corporation's common shares as at December 31, 2015 was $37.72 (December 31, 2014 – $38.96). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

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

Foreign Currency Translation

The assets and liabilities of the Corporation's foreign operations, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL, all of which have a US dollar functional currency, are translated at the exchange rate in effect as at the balance sheet date. The exchange rate in effect as at December 31, 2015 was US$1.00=CAD$1.38 (December 31, 2014 – US$1.00=CAD$1.16). The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive income until the foreign subsidiary is sold, substantially liquidated or evaluated for impairment in anticipation of disposal. Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate in effect during the reporting period, which was US$1.00=CAD$1.28 for 2015 (2014 – US$1.00=CAD$1.10).

The Corporation's approximate 33% equity investment in Belize Electricity is translated at the exchange rate in effect as at the balance sheet date. The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive income until the investment is sold, substantially liquidated or evaluated for impairment in anticipation of disposal (Notes 9 and 24).

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

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

Derivative Instruments and Hedging Activities

The Corporation and its subsidiaries use various physical and financial derivative instruments to meet forecast load and reserve requirements, to reduce exposure to fluctuations in commodity prices and foreign exchange rates, and to hedge interest rate risk exposure. The Corporation does not hold or issue derivative instruments for trading purposes and generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges. As at December 31, 2015, the Corporation's derivative instruments primarily consisted of electricity swap contracts, gas swap and option contracts, electricity power purchase contracts, gas purchase contract premiums, long-term wholesale trading contracts, and interest rate swaps (Note 31).

All derivative instruments that do not meet the normal purchase or normal sale scope exception are recognized as assets or liabilities on the consolidated balance sheet and are measured at fair value. Changes in fair value are recognized in earnings unless the instruments qualify, and are designated, as an accounting or economic hedge.

Derivative instruments that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized as energy supply costs on the consolidated statements of earnings. Derivative contracts under master netting agreements and collateral positions are presented on a gross basis. The Corporation is required to bifurcate embedded derivatives from their host instruments and account for them as free-standing derivative instruments if they meet specified criteria.

For derivatives designated as hedging contracts, the Corporation's utilities formally assess, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The hedging strategy by transaction type and risk management strategy is formally documented. As at December 31, 2015, the Corporation's hedging relationships primarily consisted of interest rate swaps and US dollar-denominated borrowings.

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

For derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates, as permitted by the respective regulators. Accordingly, the net unrealized gains and losses associated with changes in fair value of the derivative contracts are recorded as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8 *(vii)*).

Income Taxes

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

As approved by the respective regulator, UNS Energy, Central Hudson and Maritime Electric recover current and deferred income tax expense in customer rates. As approved by the regulator, FortisAlberta recovers income tax expense in customer rates based only on income taxes that are currently payable. FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax expense is recovered from, or refunded to, customers in current rates, as prescribed by the respective regulator. Therefore, with the exception of certain deferred tax balances of FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. These utilities recognize an offsetting regulatory asset or liability for the amount of deferred income taxes that are expected to be collected from or refunded to customers in rates once income taxes become payable or receivable (Note 8 *(i)*).

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

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

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

The Corporation intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, the Corporation does not provide for deferred income taxes on temporary differences related to investments in foreign subsidiaries. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $565 million as at December 31, 2015 (December 31, 2014 – $384 million). If such earnings are repatriated, in the form of dividends or otherwise, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical. Canada has entered into Tax Information Exchange Agreements ("TIEAs") with Bermuda, the Cayman Islands and the Turks and Caicos Islands. Consequently, earnings from the Corporation's foreign subsidiaries operating in these regions, subsequent to 2010, can be repatriated to Canada on a tax-free basis and, therefore, are not included in the amount of temporary differences noted above, as no taxes are payable on these earnings. If a TIEA is entered into with Belize, earnings from the Corporation's operations in Belize would also be able to be repatriated to Canada on a tax-free basis. Negotiations between the Government of Canada and the GOB commenced in June 2010.

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

Income tax interest and penalties are expensed as incurred and included in income tax expense. At FortisAlberta, investment tax credits are deducted from the related assets and are recognized as a reduction of income tax expense as the Company becomes taxable for rate-setting purposes.

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

Sales Taxes

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

For regulatory reporting purposes, Central Hudson recognizes tax revenue collected on behalf of applicable government authorities on a gross basis. In 2015 approximately $19 million was included in both revenue and expenses (2014 – $22 million).

Revenue Recognition

Revenue from the sale of electricity and gas by the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority, and is generally bundled to include service associated with generation and T&D, except at FortisAlberta and FortisOntario. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator. Effective July 1, 2015, Central Hudson is permitted by the regulator to accrue unbilled revenue for electricity consumed at each period end for all its electricity customers. As at December 31, 2014, approximately $15 million (US$13 million) in unbilled revenue at Central Hudson, associated with certain electricity customers, was not accrued, as permitted by the regulator.

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

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with AESO and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. FortisAlberta is not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers are deferred to be recovered from, or refunded to, customers in future rates (Note 8 *(xviii)*).

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

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

Non-utility revenue, associated with commercial real estate and hotel assets that were sold in 2015, was recognized when services were provided or products were delivered to customers. Specifically, real estate revenue, derived from leasing retail and office space, was recognized in the month earned at rates in accordance with lease agreements. The leases were primarily of a net nature, with tenants paying basic rent plus a pro rata share of certain defined overhead expenses. Certain retail tenants paid additional rent based on a percentage of the tenants' sales. Expenses recovered from tenants were recorded as revenue on an accrual basis. Base rent and the escalation of lease rates included in long-term leases were recognized in earnings using the straight-line method over the term of the lease.

Asset Retirement Obligations

AROs, including conditional AROs, are recorded as a liability at fair value and are classified as long-term other liabilities, with a corresponding increase to utility capital assets (Note 17). The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of AROs is based on an estimate of the present value of expected future cash outlays reflecting a range of possible outcomes, discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to reflect the passage of time and any changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities. As permitted by the respective regulator, at UNS Energy, Central Hudson and FortisBC Electric, changes in the obligations due to the passage of time are recognized as a regulatory asset using the effective interest method.

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

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights-of-way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of the fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

New Accounting Policies

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

Effective January 1, 2015, the Corporation prospectively adopted Accounting Standards Update ("ASU") No. 2014-08 that changes the criteria and disclosures for reporting discontinued operations. As a result, the sale of commercial real estate and hotel assets and the sale of non-regulated generation assets in 2015 did not meet the criteria for discontinued operations (Note 28). The sales are consistent with the Corporation's focus on its core utility business and, therefore, do not represent a strategic shift in operations.

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period

Effective January 1, 2015, the Corporation early adopted ASU No. 2014-12 that resolves diversity in practice for employee share-based payments with performance targets that can entitle an employee to benefit from an award regardless of if they are rendering services at the date the performance target is achieved. The adoption of this update was applied prospectively and did not have a material impact on the Corporation's consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs

Effective October 1, 2015, the Corporation early adopted ASU No. 2015-03 that requires debt issuance costs to be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The adoption of this update was applied retrospectively and resulted in the reclassification of debt issuance costs of approximately $65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014 (Note 36). Additionally, the Corporation early adopted ASU No. 2015-15 that clarifies the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements. The update permits an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The adoption of this update was applied retrospectively and did not have a material impact on the Corporation's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes

Effective October 1, 2015, the Corporation early adopted ASU No. 2015-17 that requires deferred tax assets and liabilities to be classified and presented as long term on the consolidated balance sheet. The adoption of this update was applied retrospectively and resulted in the reclassification of current deferred income taxes assets of $158 million, long-term deferred income tax assets of $62 million, and current deferred income tax liabilities of $9 million to long-term deferred income tax liabilities on the consolidated balance sheet as at December 31, 2014. As a result, the Corporation also reclassified current regulatory assets of $18 million, current regulatory liabilities of $19 million, and long-term regulatory liabilities of $91 million to long-term regulatory assets on the consolidated balance sheet as at December 31, 2014, all associated with regulatory deferred income taxes (Note 36).

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

Use of Accounting Estimates

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

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

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Intangible Assets, Goodwill, Employee Future Benefits, Stock-Based Compensation, Income Taxes, Revenue Recognition and Asset Retirement Obligations, and in Notes 8, 23 and 34.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

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

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the International Accounting Standards Board to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. ASU No. 2015-14 was issued in August 2015 and the amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The majority of the Corporation's revenue is generated from energy sales to customers based on published tariff rates, as approved by the respective regulators, and is expected to be in the scope of ASU No. 2014-09. Fortis has not yet selected a transition method and is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures. The Corporation plans to have this assessment substantially complete by the end of 2016.

Amendments to the Consolidation Analysis

ASU No. 2015-02 was issued in February 2015 and the amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following with regard to limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. The adoption of this update is not expected to materially impact the Corporation's consolidated financial statements, however, it is expected to change the Corporation's 51% controlling ownership interest in Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional note disclosure.

5. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED									NON-REGULATED				
	United States			Canada										
	Electric & Gas			Gas	Electric									
Year Ended December 31, 2015 *($ in millions)*	UNS Energy	Central Hudson	**Total**	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	**Total**	**Caribbean Electric**	**Fortis Generation**	**Non-Utility**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Revenue	2,034	880	**2,914**	1,295	563	360	1,033	**3,251**	**321**	**107**	**171**	**24**	**(61)**	**6,727**
Energy supply costs	820	315	**1,135**	498	–	116	673	**1,287**	**169**	**1**	**–**	**–**	**(31)**	**2,561**
Operating expenses	573	381	**954**	292	183	89	143	**707**	**46**	**19**	**124**	**26**	**(12)**	**1,864**
Depreciation and amortization	242	56	**298**	190	168	57	82	**497**	**47**	**18**	**11**	**2**	**–**	**873**
Operating income (loss)	399	128	**527**	315	212	98	135	**760**	**59**	**69**	**36**	**(4)**	**(18)**	**1,429**
Other income (expenses), net	5	8	**13**	11	3	–	2	**16**	**2**	**56**	**109**	**(8)**	**(1)**	**187**
Finance charges	98	38	**136**	134	78	39	56	**307**	**14**	**3**	**18**	**94**	**(19)**	**553**
Income tax expense (recovery)	111	40	**151**	51	(1)	9	19	**78**	**–**	**24**	**13**	**(43)**	**–**	**223**
Net earnings (loss)	195	58	**253**	141	138	50	62	**391**	**47**	**98**	**114**	**(63)**	**–**	**840**
Non-controlling interests	–	–	**–**	1	–	–	–	**1**	**13**	**21**	**–**	**–**	**–**	**35**
Preference share dividends	–	–	**–**	–	–	–	–	**–**	**–**	**–**	**–**	**77**	**–**	**77**
Net earnings (loss) attributable to common equity shareholders	195	58	**253**	140	138	50	62	**390**	**34**	**77**	**114**	**(140)**	**–**	**728**
Goodwill	1,912	624	**2,536**	913	227	235	67	**1,442**	**195**	**–**	**–**	**–**	**–**	**4,173**
Identifiable assets	6,977	2,601	**9,578**	5,116	3,592	1,872	2,219	**12,799**	**1,084**	**1,025**	**–**	**352**	**(207)**	**24,631**
Total assets	8,889	3,225	**12,114**	6,029	3,819	2,107	2,286	**14,241**	**1,279**	**1,025**	**–**	**352**	**(207)**	**28,804**
Gross capital expenditures	669	181	**850**	460	452	103	175	**1,190**	**137**	**38**	**9**	**19**	**–**	**2,243**
Year Ended December 31, 2014 *($ in millions)*														
Revenue	684	821	1,505	1,435	518	334	1,008	3,295	321	38	249	31	(38)	5,401
Energy supply costs	272	345	617	646	–	87	653	1,386	195	1	–	–	(2)	2,197
Operating expenses	209	337	546	287	176	90	143	696	39	10	172	38	(8)	1,493
Depreciation and amortization	80	49	129	190	164	59	79	492	38	5	22	2	–	688
Operating income (loss)	123	90	213	312	178	98	133	721	49	22	55	(9)	(28)	1,023
Other income (expenses), net	4	6	10	4	3	1	2	10	2	(1)	–	(45)	(1)	(25)
Finance charges	34	35	69	139	79	41	56	315	14	–	24	154	(29)	547
Income tax expense (recovery)	33	24	57	49	(1)	12	19	79	–	1	8	(79)	–	66
Net earnings (loss) from continuing operations	60	37	97	128	103	46	60	337	37	20	23	(129)	–	385
Earnings from discontinued operations, net of tax	–	–	–	–	–	–	–	–	–	–	5	–	–	5
Net earnings (loss)	60	37	97	128	103	46	60	337	37	20	28	(129)	–	390
Non-controlling interests	–	–	–	1	–	–	–	1	10	–	–	–	–	11
Preference share dividends	–	–	–	–	–	–	–	–	–	–	–	62	–	62
Net earnings (loss) attributable to common equity shareholders	60	37	97	127	103	46	60	336	27	20	28	(191)	–	317
Goodwill	1,603	523	2,126	913	227	235	67	1,442	164	–	–	–	–	3,732
Identifiable assets	5,648	2,123	7,771	4,846	3,234	1,803	2,163	12,046	924	961	696	543	(440)	22,501
Total assets	7,251	2,646	9,897	5,759	3,461	2,038	2,230	13,488	1,088	961	696	543	(440)	26,233
Gross capital expenditures	444	126	570	332	348	92	166	938	71	102	38	6	–	1,725

5. *SEGMENTED INFORMATION (cont'd)*

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions during the years ended December 31 were as follows.

Significant Related Party Inter-Segment Transactions

(in millions)	**2015**	2014
Sales from Fortis Generation to Regulated Electric Utilities – Canadian	**$ 31**	$ 2
Revenue from Regulated Electric Utilities – Canadian to Fortis Generation	**7**	–
Sales from Regulated Electric Utilities – Canadian to Non-Utility	**4**	6
Inter-segment finance charges on lending from:		
Fortis Generation to Eastern Canadian Electric Utilities	**1**	1
Corporate to Regulated Electric Utilities – Caribbean	**–**	5
Corporate to Non-Utility	**17**	22

The significant related party inter-segment asset balances as at December 31 were as follows.

Significant Related Party Inter-Segment Assets

(in millions)	**2015**	2014
Inter-segment borrowings from:		
Fortis Generation to Eastern Canadian Electric Utilities	**$ 20**	$ 20
Corporate to Regulated Electric Utilities – Canadian	**48**	–
Corporate to Non-Utility	**–**	402
Other inter-segment assets – Corporate to Regulated Electric & Gas Utilities – United States	**108**	–
Other inter-segment assets	**31**	18
Total inter-segment eliminations	**$ 207**	$ 440

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	**2015**	2014
Trade accounts receivable	**$ 517**	$ 479
Unbilled accounts receivable	**404**	365
Allowance for doubtful accounts	**(66)**	(31)
Income tax receivable	**–**	25
Assets held for sale	**38**	–
Other	**71**	62
	$ 964	$ 900

The increase in the allowance for doubtful accounts was primarily due to an increase in the reserve for uncollectible accounts at UNS Energy in relation to billings to third-party owners of Springerville Unit 1 for their pro-rata share of costs to operate the facility. Due to ongoing litigation and uncertainty with Springerville Unit 1 third-party owners, the accounts receivable balance of $32 million (US$23 million) as at December 31, 2015 associated with operating expenses has been fully reserved (Note 34).

Assets held for sale include utility capital assets of approximately $29 million (US$21 million) purchased by UNS Energy upon expiration of the Springerville Coal Handling Facilities lease in April 2015 (Note 16). UNS Energy has an agreement with a third party whereby they can purchase a 17.05% interest or continue to make payments to UNS Energy for the use of the facility. The third party has until April 2016 to exercise its purchase option and, as a result, the assets have been classified as held for sale on the consolidated balance sheet as at December 31, 2015.

Additionally, in December 2015 FortisBC Electric entered into an agreement to sell the non-regulated Walden hydroelectric power plant assets for a sale price of approximately $9 million (Note 31). The sale is expected to close in the first quarter of 2016. For the year ended December 31, 2015, earnings before taxes of less than $1 million were recognized (December 31, 2014 – less than $1 million) associated with Walden.

Other accounts receivable consisted of customer billings for non-core services, collateral deposits for gas purchases at FortisBC Energy and advances on coal purchases at UNS Energy. Other accounts receivable also included the fair value of derivative instruments (Note 31).

7. INVENTORIES

(in millions)	**2015**	2014
Materials and supplies	**$ 194**	$ 149
Gas and fuel in storage	**101**	134
Coal inventory	**42**	38
	$ 337	$ 321

Materials and supplies included approximately $152 million (December 31, 2014 – $118 million) at UNS Energy, and consisted of construction and repair materials for distribution, transmission and generation assets, as required by the regulator (Note 3).

8. REGULATORY ASSETS AND LIABILITIES

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

(in millions)	**2015**	2014	**Remaining recovery period** *(Years)*
Regulatory assets			
Deferred income taxes *(i)*	**$ 936**	$ 832	To be determined
Employee future benefits *(ii)*	**627**	680	Various
Deferred energy management costs *(iii)*	**145**	111	1–10
Manufactured gas plant ("MGP") site remediation deferral *(iv)*	**121**	123	To be determined
Rate stabilization accounts *(v)*	**119**	119	Various
Deferred lease costs *(vi)*	**90**	101	Various
Derivative instruments *(vii)*	**74**	69	Various
Deferred operating overhead costs *(viii)*	**66**	54	Various
Final mine reclamation and retiree health care costs *(ix)*	**39**	34	1–22
Deferred net losses on disposal of utility capital assets and intangible assets *(x)*	**33**	37	8
Springerville Unit 1 unamortized leasehold improvements *(xi)*	**30**	–	8
Property tax deferrals *(xii)*	**30**	29	1
Other regulatory assets *(xiii)*	**222**	226	Various
Total regulatory assets	**2,532**	2,415	
Less: current portion	**(246)**	(277)	1
Long-term regulatory assets	**$ 2,286**	$ 2,138	

For the years ended December 31, 2015 and 2014

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

(in millions)	**2015**	2014	**Remaining recovery period** *(Years)*
Regulatory liabilities			
Non-ARO removal cost provision *(xiv)*	**$ 1,060**	$ 951	To be determined
Rate stabilization accounts *(v)*	**212**	142	Various
Electric and gas moderator account *(xv)*	**88**	–	To be determined
Renewable energy surcharge *(xvi)*	**47**	44	To be determined
Employee future benefits *(ii)*	**44**	58	Various
Customer and community benefits obligation *(xvii)*	**32**	55	To be determined
AESO charges deferral *(xviii)*	**25**	49	1–4
Other regulatory liabilities *(xix)*	**130**	146	Various
Total regulatory liabilities	**1,638**	1,445	
Less: current portion	**(298)**	(173)	1
Long-term regulatory liabilities	**$ 1,340**	$ 1,272	

Description of the Nature of Regulatory Assets and Liabilities

(i) *Deferred Income Taxes*

The Corporation's regulated utilities recognize deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future electricity and gas rates. Included in deferred income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates. The deferred income taxes on regulatory assets and liabilities are the result of the application of ASC Topic 740, *Income Taxes*. The regulatory asset balances are expected to be recovered from customers in future rates when the income taxes become payable or receivable. As at December 31, 2015, $351 million (December 31, 2014 – $265 million) in regulatory assets for deferred income taxes was not subject to a regulatory return.

(ii) *Employee Future Benefits*

The regulatory asset and liability associated with employee future benefits includes the actuarially determined unamortized net actuarial losses, past service costs and credits, and transitional obligations associated with defined benefit pension and OPEB plans maintained by the Corporation's regulated utilities, which are expected to be recovered from, or refunded to, customers in future rates (Note 27). At the Corporation's regulated utilities, as approved by the respective regulators, differences between defined benefit pension and OPEB plan costs recognized under US GAAP and those which are expected to be recovered from, or refunded to, customers in future rates are subject to deferral account treatment and have been recognized as a regulatory asset or liability. These amounts would otherwise be recognized in accumulated other comprehensive income on the consolidated balance sheet.

As at December 31, 2015, regulatory assets of approximately $367 million associated with employee future benefits were not subject to a regulatory return (December 31, 2014 – $339 million). As at December 31, 2015, regulatory liabilities of approximately $36 million associated with employee future benefits were not subject to a regulatory return (December 31, 2014 – $55 million).

(iii) *Deferred Energy Management Costs*

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

UNS Energy is required to implement cost-effective Demand-Side Management ("DSM") programs to comply with the ACC's energy efficiency standards. The energy efficiency standards provide for a DSM surcharge to recover the costs of implementing DSM programs, as well as an annual performance incentive. The existing rate orders provide for a lost fixed cost recovery mechanism to recover certain non-fuel costs that were previously unrecoverable, due to reduced electricity sales as a result of energy efficiency programs and distributed generation. As at December 31, 2015, $25 million of UNS Energy's regulatory asset balance was not subject to a regulatory return (December 31, 2014 – $16 million).

(iv) MGP Site Remediation Deferral

As approved by the regulator, Central Hudson is permitted to defer for future recovery from its customers the difference between actual costs for MGP site investigation and remediation and the associated rate allowances (Notes 14, 17 and 34). Central Hudson's MGP site remediation costs are not subject to a regulatory return.

(v) Rate Stabilization Accounts

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

As at December 31, 2015, approximately $49 million and $142 million of the rate stabilization accounts are expected to be recovered from, or refunded to, customers within one year and, as a result, are classified as current regulatory assets and liabilities, respectively (December 31, 2014 – approximately $105 million and $43 million, respectively).

As at December 31, 2015, regulatory assets of approximately $44 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2014 – $104 million). As at December 31, 2015, regulatory liabilities of approximately $76 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2014 – $42 million).

(vi) Deferred Lease Costs

Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA"), which ends in 2056. The depreciation of the asset under capital lease and interest expense associated with the capital lease obligation are not being fully recovered by FortisBC Electric in current customer rates, since those rates include only the cash payments set out under the BPPA. The regulatory asset balance as at December 31, 2015 included $90 million (December 31, 2014 – $83 million) of deferred lease costs that are expected to be recovered from customers in future rates over the term of the lease. In 2015, of the $30 million (2014 – $30 million) of interest expense related to the capital lease obligations and the $6 million (2014 – $6 million) of depreciation expense related to the assets under capital lease, a total of $26 million (2014 – $26 million) was recognized in energy supply costs and $3 million (2014 – $3 million) was recognized in operating expenses, respectively, as approved by the regulator, with the balance of $7 million (2014 – $7 million) deferred as a regulatory asset (Note 16).

The regulatory asset balance as at December 31, 2014 included $18 million of deferred lease costs at UNS Energy related to the remaining purchase commitments of Springerville Unit 1 and the Springerville Coal Handling Facility, of which both purchases occurred in 2015 (Note 16).

Deferred lease costs are not subject to a regulatory return.

(vii) Derivative Instruments

As approved by the respective regulatory authority, unrealized gains or losses associated with changes in the fair value of certain derivative instruments at UNS Energy, Central Hudson and FortisBC Energy are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. These unrealized losses and gains would otherwise be recognized in earnings (Note 31). UNS Energy and Central Hudson's deferred regulatory asset balance totalling $57 million as at December 31, 2015 was not subject to a regulatory return (December 31, 2014 – $57 million).

(viii) Deferred Operating Overhead Costs

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

(ix) Final Mine Reclamation and Retiree Health Care Costs

Final mine reclamation and retiree health care costs are associated with TEP's jointly owned coal generating facilities at the San Juan, Four Corners and Navajo generating stations. TEP has the option to recognize its liability associated with final mine reclamation and retiree health care obligations at present or future value (Notes 17 and 34). TEP has elected to recognize these costs at future value and is permitted to fully recover these costs from customers through its rate stabilization accounts when the costs are paid. TEP expects to make continuous payments through 2037. These deferred costs are not subject to a regulatory return.

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

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

(x) Deferred Net Losses on Disposal of Utility Capital Assets and Intangible Assets

As approved by the regulator, from 2010 through 2013 net losses on the retirement or disposal of utility capital assets and intangible assets at FortisBC Energy were recorded in a regulatory deferral account to be recovered from customers in future rates. The regulator approved the recovery in customer rates of the resulting regulatory asset over a period of 10 years.

(xi) Springerville Unit 1 Unamortized Leasehold Improvements

Upon expiration of TEP's Springerville Unit 1 capital lease in January 2015, unamortized leasehold improvements were reclassified from utility capital assets to regulatory assets. The leasehold improvements represent investments made by TEP through the end of the lease term to ensure Springerville facilities continued providing safe, reliable service to TEP's customers. In its 2013 rate order, TEP received regulatory approval to amortize the leasehold improvements over a 10-year period. TEP continues to own an undivided 49.5% joint interest in Springerville Unit 1.

(xii) Property Tax Deferrals

Property taxes at UNS Energy and Central Hudson are deferred and are primarily collected from customers over a six-month to one-year period, as approved by the respective regulator. Property tax deferrals are not subject to a regulatory return.

(xiii) Other Regulatory Assets

Other regulatory assets relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $30 million. As at December 31, 2015, $189 million (December 31, 2014 – $177 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2015, $69 million (December 31, 2014 – $74 million) of the balance was not subject to a regulatory return.

(xiv) Non-ARO Removal Cost Provision

As required by the respective regulator, depreciation rates at UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to accrue for non-ARO removal costs. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. This regulatory liability represents amounts collected in customer electricity rates at the respective utilities in excess of incurred non-ARO removal costs.

(xv) Electric and Gas Moderator Account

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

(xvi) Renewable Energy Surcharge

As ordered by the regulator under its Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. The Company must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out the plan is recovered from retail customers through the RES surcharge. The ACC has also approved recovery of operating costs, depreciation, property taxes and return on investments on certain company-owned solar projects through the RES tariff until such costs are reflected in retail customer rates. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory asset or liability.

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

(xvii) Customer and Community Benefits Obligation

As approved by the respective regulator for UNS Energy and Central Hudson, Fortis committed to provide their customers and community with financial benefits that would have not been realized in the absence of the acquisitions. These commitments resulted in the recognition of regulatory liabilities to be used to mitigate future customer rate increase at the utilities. In 2014 these commitments for UNS Energy's customers included US$10 million in year one and US$5 million in years two through five to cover credits in retail customer rates. As a result, expenses of approximately $33 million (US$30 million) were recognized in 2014 related to the acquisition of UNS Energy for customer benefit obligations (Notes 24 and 29).

(xviii) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenue collected for various items, such as transmission costs incurred and flowed through to customers, that are subject to deferral to be collected in future customer rates. To the extent that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be refunded in future customer rates. As at December 31, 2015, the regulatory liability primarily represented the over collection of the AESO charges deferral accounts for 2014 and 2015.

(xix) Other Regulatory Liabilities

Other regulatory liabilities relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $30 million. As at December 31, 2015, $120 million (December 31, 2014 – $140 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2015, $68 million (December 31, 2014 – $76 million) of the balance was not subject to a regulatory return.

9. OTHER ASSETS

(in millions)	**2015**	2014
Equity investment – Belize Electricity	**$ 79**	$ –
Supplemental Executive Retirement Plan assets	**58**	41
Deposit on pending business acquisition *(Note 29)*	**38**	–
Available-for-sale investment *(Notes 28 and 31)*	**33**	–
Deferred compensation plan assets *(Note 17)*	**25**	21
Renewable Energy Credits *(Note 8 (xvi))*	**17**	13
Long-term income tax receivable	**13**	13
Other investments	**13**	12
Other asset – Belize Electricity	**–**	116
Other	**76**	56
	$ 352	$ 272

In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the GOB's 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. As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015 (Note 24).

UNS Energy and Central Hudson provide additional post-employment benefits through both a deferred compensation plan for Directors and Officers of the Companies, as well as Supplemental Executive Retirement Plans ("SERP"). Since both plans are considered non-qualified plans under the *Employee Retirement Income Security Act of 1974*, the assets are reported separately from the related liabilities (Note 17). The assets of the plans are held in trust and funded mostly through the use of trust-owned life insurance policies and mutual funds. A portion of the SERP assets is invested in corporate-owned life insurance policies. Amounts held in mutual and money market funds are recorded at fair value (Note 31).

In June 2015 the Corporation completed the sale of commercial real estate assets for gross proceeds of $430 million (Note 28). As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering. The investment in trust units is recorded as an available-for-sale asset. The assets are measured at fair value based on quoted market prices and unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold (Notes 21 and 31).

Other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable. Other assets include the fair value of derivative instruments at UNS Energy and Central Hudson (Note 31).

For the years ended December 31, 2015 and 2014

10. UTILITY CAPITAL ASSETS

2015

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 9,245	$ (2,634)	$ 6,611
Gas	3,829	(1,021)	2,808
Transmission			
Electric	3,093	(997)	2,096
Gas	1,735	(531)	1,204
Generation	6,465	(2,241)	4,224
Other	2,429	(849)	1,580
Assets under construction	886	–	886
Land	186	–	186
	$ 27,868	$ (8,273)	$ 19,595

2014

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 8,102	$ (2,317)	$ 5,785
Gas	3,475	(920)	2,555
Transmission			
Electric	2,562	(859)	1,703
Gas	1,649	(491)	1,158
Generation	5,296	(2,189)	3,107
Other	2,158	(731)	1,427
Assets under construction	1,277	–	1,277
Land	167	–	167
	$ 24,686	$ (7,507)	$ 17,179

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

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

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

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

Construction of the Waneta Expansion was completed in April 2015. As at December 31, 2015, assets under construction are primarily associated with FortisBC Energy's Tilbury liquefied natural gas facility expansion and other capital projects at the Corporation's regulated utilities.

The cost of utility capital assets under capital lease as at December 31, 2015 was $496 million (December 31, 2014 – $1,088 million) and related accumulated depreciation was $221 million (December 31, 2014 – $627 million). The decrease was primarily due to the purchase of certain utility capital assets at TEP in 2015 following the expiry of lease arrangements (Note 16).

Jointly Owned Facilities

As at December 31, 2015, UNS Energy's interests in jointly owned generating stations and transmission systems primarily consisted of the following:

2015

(in millions)	**Ownership** *(%)*		**Cost**		**Accumulated Depreciation**		**Net Book Value**
San Juan Units 1 and 2	50.0	**$**	**690**	**$**	**(347)**	**$**	**343**
Navajo Units 1, 2 and 3	7.5		**207**		**(155)**		**52**
Four Corners Units 4 and 5	7.0		**154**		**(107)**		**47**
Luna Energy Facility	33.3		**75**		**(1)**		**74**
Gila River Common Facilities	25.0		**47**		**(14)**		**33**
Springerville Unit 1 [(1)]	49.5		**452**		**(240)**		**212**
Springerville Coal Handling Facilities [(2)]	65.9		**228**		**(90)**		**138**
Transmission Facilities	Various		**531**		**(238)**		**293**
		$	**2,384**	**$**	**(1,192)**	**$**	**1,192**

(1) TEP is obligated to operate the unit for third-party owners under existing agreements. The third-party owners are obligated to compensate TEP for their pro rata share of expenses (Notes 16 and 34).

(2) TEP owns an additional 17.05% undivided interest in the Springerville Coal Handling Facilities, which is classified as assets held for sale (Notes 6 and 16).

UNS Energy holds an undivided interest in the above facilities and is entitled to its pro rata share of the utility capital assets. UNS Energy is proportionately liable for its share of operating costs and liabilities in respect of the jointly owned facilities.

11. NON-UTILITY CAPITAL ASSETS

In 2015 the Corporation sold its commercial real estate and hotel assets (Note 28). As a result, the Corporation did not hold any non-utility capital assets as at December 31, 2015.

2014

(in millions)		Cost		Accumulated Depreciation		Net Book Value
Buildings	$	599	$	(105)	$	494
Equipment		145		(73)		72
Tenant inducements		35		(27)		8
Land		72		–		72
Assets under construction		18		–		18
	$	869	$	(205)	$	664

12. INTANGIBLE ASSETS

2015

(in millions)		**Cost**		**Accumulated Amortization**		**Net Book Value**
Computer software	**$**	**685**	**$**	**(436)**	**$**	**249**
Land, transmission and water rights		**328**		**(76)**		**252**
Franchise fees and other		**17**		**(13)**		**4**
Assets under construction		**36**		**–**		**36**
	$	**1,066**	**$**	**(525)**	**$**	**541**

For the years ended December 31, 2015 and 2014

12. INTANGIBLE ASSETS (cont'd)

2014

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 573	$ (368)	$ 205
Land, transmission and water rights	258	(66)	192
Franchise fees and other	16	(12)	4
Assets under construction	60	–	60
	$ 907	$ (446)	$ 461

Included in the cost of land, transmission and water rights as at December 31, 2015 was $106 million (December 31, 2014 – $77 million) not subject to amortization.

Amortization expense related to intangible assets was $64 million for 2015 (2014 – $60 million). Amortization is estimated to average approximately $78 million annually for each of the next five years.

13. GOODWILL

(in millions)	**2015**	2014
Balance, beginning of year	**$ 3,732**	$ 2,075
Acquisition of UNS Energy *(Note 29)*	**–**	1,510
Sale of Griffith *(Note 28)*	**–**	(3)
Foreign currency translation impacts	**441**	150
Balance, end of year	**$ 4,173**	$ 3,732

Goodwill associated with the acquisitions of UNS Energy, Central Hudson, Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the functional currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

14. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)	**2015**	2014
Trade accounts payable	**$ 574**	$ 612
Gas and fuel cost payable	**153**	195
Employee compensation and benefits payable	**137**	134
Interest payable	**127**	128
Dividends payable	**113**	101
Accrued taxes other than income taxes	**108**	96
Fair value of derivative instruments *(Note 31)*	**69**	66
MGP site remediation *(Notes 8 (iv), 17 and 34)*	**32**	13
Defined benefit pension and OPEB plan liabilities *(Note 27)*	**13**	11
Other	**93**	84
	$ 1,419	$ 1,440

Accrued taxes other than income taxes primarily consisted of property taxes at UNS Energy and carbon tax at FortisBC Energy.

15. LONG-TERM DEBT

(in millions)	Maturity Date	2015	2014
Regulated Utilities			
UNS Energy			
Unsecured US Tax-Exempt Bonds –			
3.83% weighted average fixed and variable rate (2014 – 3.92%)	2020 – 2040	**$ 848**	$ 956
Unsecured US Fixed Rate Notes –			
4.26% weighted average fixed rate (2014 – 4.98%)	2021 – 2045	**1,557**	754
Secured US Fixed Rate Notes –			
5.38% weighted average fixed and variable rate (2014 – 5.38%)	2023 – 2026	**–**	151
Central Hudson			
Unsecured US Promissory Notes –			
4.30% weighted average fixed and variable rate (2014 – 4.31%)	2016 – 2042	**728**	587
FortisBC Energy			
Secured Purchase Money Mortgages –			
10.30% weighted average fixed rate (2014 – 10.71%)	2016	**200**	275
Unsecured Debentures –			
5.73% weighted average fixed rate (2014 – 5.95%)	2029 – 2045	**1,770**	1,620
Government loan	2016	**5**	10
FortisAlberta			
Unsecured Debentures –			
4.95% weighted average fixed rate (2014 – 5.01%)	2024 – 2052	**1,684**	1,534
FortisBC Electric			
Secured Debentures –			
8.80% weighted average fixed rate (2014 – 8.80%)	2023	**25**	25
Unsecured Debentures –			
5.36% weighted average fixed rate (2014 – 5.36%)	2016 – 2050	**660**	660
Eastern Canadian			
Secured First Mortgage Sinking Fund Bonds –			
6.72% weighted average fixed rate (2014 – 7.08%)	2016 – 2045	**553**	484
Secured First Mortgage Bonds –			
7.18% weighted average fixed rate (2014 – 7.18%)	2016 – 2061	**167**	167
Unsecured Senior Notes –			
6.11% weighted average fixed rate (2014 – 6.11%)	2018 – 2041	**104**	104
Caribbean Electric			
Unsecured US Senior Loan Notes –			
4.89% weighted average fixed rate (2014 – 4.91%)	2016 – 2046	**467**	400
Non-Regulated – Non-Utility			
Secured First Mortgages and Senior Notes –			
7.46% weighted average fixed rate (2014 – 7.46%)	n/a	**–**	34
Corporate			
Unsecured US Senior Notes and Promissory Notes –			
4.43% weighted average fixed rate (2014 – 4.43%)	2019 – 2044	**1,720**	1,443
Unsecured Debentures –			
6.49% weighted average fixed rate (2014 – 6.49%)	2039	**201**	201
Long-term classification of credit facility borrowings *(Note 31)*		**551**	1,096
Total long-term debt *(Note 31)*		**11,240**	10,501
Less: Deferred financing costs *(Notes 3 and 36)*		**(72)**	(65)
Less: Current installments of long-term debt		**(384)**	(525)
		$ 10,784	$ 9,911

For the years ended December 31, 2015 and 2014

15. LONG-TERM DEBT (cont'd)

As noted in the previous table, certain long-term debt instruments issued by UNS Energy, FortisBC Energy, FortisBC Electric, Newfoundland Power, and Maritime Electric are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the Company to which the long-term debt is associated. The purchase money mortgages of FortisBC Energy are secured equally and ratably by a first fixed and specific mortgage and charge on the Company's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be issued is limited to $350 million.

UNS Energy entered into a four-year US$30 million variable rate term loan credit agreement and, at the same time, entered into a fixed-for-floating interest rate swap. Both the term loan and interest rate swap expired in 2015. The interest rate swap was designated as a cash flow hedge (Note 31).

Covenants

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at December 31, 2015, the Corporation and its subsidiaries were in compliance with their debt covenants.

Regulated Utilities

The majority of the long-term debt instruments at the Corporation's regulated utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

In January 2015 TEP redeemed at par US$130 million of fixed rate tax-exempt bonds that had an original maturity date of 2029. As at December 31, 2015, TEP had not remarketed the repurchase bonds.

In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures.

In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes.

In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings and for general corporate purposes.

In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured debentures and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt. Additionally, in August 2015 TEP redeemed at par US$79 million of variable rate tax-exempt bonds that had an original maturity date of 2022.

In September 2015 FortisAlberta issued 30-year $150 million 4.27% unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

Corporate

The unsecured debentures and US senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

Repayment of Long-Term Debt

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

Year	Subsidiaries (in millions)	Corporate (in millions)	Total (in millions)
2016	$ 382	$ 2	$ 384
2017	69	2	71
2018	281	2	283
2019	112	127	239
2020	202	655	857
Thereafter	7,793	1,613	9,406
	$ 8,839	$ 2,401	$ 11,240

16. CAPITAL LEASE AND FINANCE OBLIGATIONS

Capital Lease Obligations

UNS Energy

In 2014 and 2015, TEP purchased certain Springerville assets upon expiry of the lease arrangements, as detailed below. As at December 31, 2015, capital lease obligations at TEP consist of an undivided one-half interest in certain Springerville Common Facilities.

Springerville Unit 1 Capital Lease Purchases

In December 2014 and January 2015, upon expiration of the Springerville Unit 1 lease, TEP purchased an additional 35.4% ownership interest in the previously leased assets for US$20 million and US$46 million, respectively. As a result of the purchases, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity. Furthermore, TEP is obligated to operate the unit for the third-party owners under an existing agreement. The third-party owners are obligated to compensate TEP for their pro rata share of expenditures (Note 34).

Springerville Coal Handling Facilities Lease Purchase

In April 2015, upon expiration of the Springerville Coal Handling Facilities lease, TEP purchased an 86.7% ownership interest in the previously leased coal handling assets for a total of US$120 million. In May 2015 TEP sold a 17.05% interest in the facilities to a third party for US$24 million and has an agreement with another third party to either purchase a 17.05% interest for US$24 million or to continue to make payments to TEP for the use of the facility. The third party has until April 2016 to exercise its purchase option and, as a result, the associated assets have been classified as held for sale on the consolidated balance sheet as at December 31, 2015 (Note 6).

Springerville Common Facilities Leases

TEP is party to three Springerville Common Facilities leases, which have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025 (Note 33). Instead of extending the leases, TEP may exercise a fixed-price purchase provision of US$38 million in 2017 and US$68 million in 2021. TEP has agreements with third parties that if the Springerville Common Facilities leases are not renewed, TEP will exercise the purchase options under these contracts. The third parties would be obligated to buy a portion of these facilities or continue to make payments to TEP for the use of these facilities.

UNS Energy entered into an interest rate swap that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease debt. As at December 31, 2015, interest on the lease debt is payable at a six-month LIBOR plus a spread of 1.88% (December 31, 2014 – 1.75%). The swap has the effect of fixing the interest rates on a portion of the amortizing principal balances of US$29 million (December 31, 2014 – US$33 million). The interest rate swap expires in 2020 and is recorded as a cash flow hedge (Note 31).

The Springerville Common Facilities capital lease obligation bears interest at a rate of 5.08%. For the year ended December 31, 2015, in total $5 million (December 31, 2014 – $2 million) of interest expense on the Springerville capital lease obligations was recognized in finance charges and $3 million (December 31, 2014 – $3 million) and $8 million (December 31, 2014 – $7 million) of depreciation expense on the Springerville leased assets was recognized in energy supply costs and depreciation, respectively.

16. CAPITAL LEASE AND FINANCE OBLIGATIONS (cont'd)

FortisBC Electric

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant Plant located near Castlegar, British Columbia. FortisBC Electric operates and maintains the Brilliant Plant, under the BPPA which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Due to the fixed annual escalators, the interest expense on the capital lease obligation presently exceeds the required payments. The capital lease obligation will continue to increase through to 2024, and subsequently decrease for the remainder of the term when the required payments exceed the interest expense on the capital lease obligation. Approximately 94% of the output from the Brilliant Plant is being purchased by FortisBC Electric through the BPPA.

The BPPA capital lease obligation bears interest at a composite rate of 5.00%. Included in energy supply costs for 2015 was $26 million (2014 – $26 million) recognized in accordance with the BPPA, as approved by the BCUC (Note 8 *(vi)*).

FortisBC Electric also has a capital lease obligation with respect to the operation of the Brilliant Terminal Station ("BTS"), under an agreement which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 9.00%. Included in operating expenses for 2015 was $3 million (2014 – $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC (Note 8 *(vi)*).

Finance Obligations

Between 2000 and 2005 FEI entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI from the municipalities. The natural gas distribution assets are considered to be integral equipment to real estate assets and, as such, the transactions have been accounted for as finance transactions. The proceeds from these transactions have been recognized as finance obligations on the consolidated balance sheet. Lease payments, net of the portion considered to be interest expense, reduce the finance obligations.

Obligations under the above-noted lease-in lease-out transactions at FEI have implicit interest at rates ranging from 6.82% to 8.66% and are being repaid over a 35-year period. Each of the lease-in lease-out arrangements allows FEI, at its option, to terminate the lease arrangements early, after 17 years. If the Company exercises this option, FEI would pay the municipality an early termination payment which is equal to the carrying value of the obligation at that point in time.

Repayment of Capital Lease and Finance Obligations

The present value of the minimum lease payments required for the capital lease and finance obligations over the next five years and thereafter are as follows:

Year	Capital Leases *(in millions)*	Finance Obligations *(in millions)*	Total *(in millions)*
2016	$ 68	$ 4	$ 72
2017	70	4	74
2018	61	32	93
2019	62	15	77
2020	73	2	75
Thereafter	2,049	38	2,087
	$ 2,383	$ 95	$ 2,478
Less: Amounts representing imputed interest and executory costs on capital lease and finance obligations			(1,965)
Total capital lease and finance obligations			513
Less: Current portion			(26)
			$ 487

17. OTHER LIABILITIES

(in millions)	**2015**	2014
OPEB plan liabilities *(Note 27)*	**$ 385**	$ 403
Defined benefit pension plan liabilities *(Note 27)*	**368**	390
MGP site remediation *(Notes 8 (iv), 14 and 34)*	**96**	109
Waneta Partnership promissory note *(Notes 31 and 33)*	**56**	53
Asset retirement obligations	**49**	37
Final mine reclamation and retiree health care liabilities *(Notes 8 (ix) and 34)*	**39**	34
Customer security deposits	**38**	26
Deferred compensation plan liabilities *(Note 9)*	**25**	21
DSU, PSU and RSU liabilities *(Note 23)*	**20**	17
Fair value of derivative instruments *(Note 31)*	**13**	13
Other	**63**	38
	$ 1,152	$ 1,141

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2015, its discounted net present value was $56 million (December 31, 2014 – $53 million). The promissory note was incurred by the Waneta Partnership on the acquisition of certain intangible assets and project design costs, from a company affiliated with CPC/CBT, associated with the construction of the Waneta Expansion. The promissory note is payable on April 1, 2020, the fifth anniversary of the commercial operation date of the Waneta Expansion.

As at December 31, 2015, UNS Energy, Central Hudson and FortisBC Electric recognized asset retirement obligations.

Other liabilities primarily include long-term accrued liabilities, deferred lease revenue, funds received in advance of expenditures and unrecognized tax benefits.

18. COMMON SHARES

Common shares issued during the year were as follows:

	2015		2014	
	Number of Shares *(in thousands)*	**Amount *(in millions)***	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	**275,997**	**$ 5,667**	213,165	$ 3,783
Conversion of Convertible Debentures	**24**	**1**	58,545	1,747
Dividend Reinvestment Plan	**4,272**	**157**	2,495	82
Consumer Share Purchase Plan	**28**	**1**	33	1
Employee Share Purchase Plan	**356**	**13**	384	12
Stock Option Plans	**885**	**28**	1,375	42
Balance, end of year	**281,562**	**$ 5,867**	275,997	$ 5,667

Convertible Debentures

To finance a portion of the acquisition of UNS Energy, in January 2014, Fortis completed the sale of $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures, represented by Installment Receipts ("Convertible Debentures"). The Convertible Debentures were sold on an installment basis at a price of $1,000 per Convertible Debenture, of which $333 was paid on closing in January 2014 and the remaining $667 was paid on October 27, 2014 (the "Final Installment Date"). Prior to the Final Installment Date, the Convertible Debentures were represented by Installment Receipts, which were traded on the TSX under the symbol "FTS.IR". Since the Final Installment Date occurred prior to the first anniversary of the closing of the offering, holders of Convertible Debentures received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing interest that would have accrued from the day following the Final Installment Date to and including January 9, 2015. Approximately $72 million ($51 million after tax) in interest expense associated with the Convertible Debentures, including the make-whole payment, was recognized in 2014 (Note 25).

For the years ended December 31, 2015 and 2014

18. COMMON SHARES (cont'd)

Convertible Debentures (cont'd)

At the option of the holders, each Convertible Debenture was convertible into common shares of Fortis at any time after the Final Installment Date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per common share, being a conversion rate of 32.5521 common shares per $1,000 principal amount of Convertible Debentures. On October 28, 2014, approximately 58.2 million common shares of Fortis were issued, representing conversion into common shares of more than 99% of the Convertible Debentures. As at December 31, 2015, a total of approximately 58.6 million common shares of Fortis were issued on the conversion of Convertible Debentures, for proceeds of $1.748 billion, net of after-tax expenses. The net proceeds were used to finance a portion of the acquisition of UNS Energy (Note 29).

19. EARNINGS PER COMMON SHARE

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 278.6 million for 2015 and 225.6 million for 2014.

Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

EPS were as follows:

	2015						
	Net Earnings to Common Shareholders *(in millions)*			**Weighted Average Number of Shares *(millions)***	**EPS**		
	Continuing Operations	**Discontinued Operations**	**Total**		**Continuing Operations**	**Discontinued Operations**	**Total**
Basic EPS	**$ 728**	**$ –**	**$ 728**	**278.6**	**$ 2.61**	**$ –**	**$ 2.61**
Effect of potential dilutive securities:							
Stock Options	**–**	**–**	**–**	**0.7**			
Preference Shares	**10**	**–**	**10**	**5.4**			
Diluted EPS	**$ 738**	**$ –**	**$ 738**	**284.7**	**$ 2.59**	**$ –**	**$ 2.59**

	2014						
	Net Earnings to Common Shareholders *(in millions)*			Weighted Average Number of Shares *(millions)*	EPS		
	Continuing Operations	Discontinued Operations	Total		Continuing Operations	Discontinued Operations	Total
Basic EPS	$ 312	$ 5	$ 317	225.6	$ 1.39	$ 0.02	$ 1.41
Effect of potential dilutive securities:							
Stock Options	–	–	–	0.5			
Preference Shares	10	–	10	6.9			
	322	5	327	233.0			
Deduct anti-dilutive impacts:							
Preference Shares	(10)	–	(10)	(6.9)			
Diluted EPS	$ 312	$ 5	$ 317	226.1	$ 1.38	$ 0.02	$ 1.40

20. PREFERENCE SHARES

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value
(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		2015		2014	
First Preference Shares	Annual Dividend Per Share	**Number of Shares**	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Series E [(1)]	$ 1.2250	**7,993,500**	**$ 197**	7,993,500	$ 197
Series F [(1)]	$ 1.2250	**5,000,000**	**122**	5,000,000	122
Series G [(2)]	$ 0.9708	**9,200,000**	**225**	9,200,000	225
Series H [(2) (3)]	$ 0.6250	**7,024,846**	**172**	10,000,000	245
Series I [(4)]		**2,975,154**	**73**	–	–
Series J [(1)]	$ 1.1875	**8,000,000**	**196**	8,000,000	196
Series K [(2)]	$ 1.0000	**10,000,000**	**244**	10,000,000	244
Series M [(2)]	$ 1.0250	**24,000,000**	**591**	24,000,000	591
		74,193,500	**$ 1,820**	74,193,500	$ 1,820

(1) Cumulative Redeemable First Preference Shares
(2) Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares
(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.
(4) Cumulative Redeemable Five-Year Floating Rate Preference Shares. 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%.

In September 2014 the Corporation issued 24 million Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M ("First Preference Shares, Series M") at a price of $25.00 per share for net after-tax proceeds of $591 million.

Holders of the First Preference Shares, Series E, Series F and Series J are each entitled to receive a fixed cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal quarterly installments on the first day of each quarter.

On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradeable common shares of the Corporation, determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time. If a holder of First Preference Shares, Series E elects to convert any 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.

The Corporation has the option to 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 First Preference Share, Series E may be converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time.

The First Preference Shares, Series G, Series H, Series K and Series M are entitled to receive fixed cumulative cash dividends as and when declared by the Board of Directors of the Corporation in the amounts of $0.9708, $0.6250, $1.0000 and $1.0250 per share per annum, respectively, for each year up to but excluding September 1, 2018, June 1, 2020, March 1, 2019, and December 1, 2019, respectively. The dividends are payable in equal quarterly installments on the first day of each quarter. As at September 1, 2018, June 1, 2020, March 1, 2019, and December 1, 2019, and each five-year period thereafter, the holders of First Preference Shares, Series G, Series H, Series K and Series M, respectively, are entitled to receive reset fixed cumulative cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preference Shares, Series G, Series H, Series K and Series M, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%, 1.45%, 2.05% and 2.48%, respectively.

20. PREFERENCE SHARES (cont'd)

On each First Preference Shares, Series H, Series K and Series M Conversion Date, the holders of First Preference Shares, Series H, Series K and Series M have the option to convert any or all of their First Preference Shares, Series H, Series K and Series M into an equal number of cumulative redeemable floating rate First Preference Shares, Series I, Series L and Series N, respectively. 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.

The holders of First Preference Shares, Series I are entitled to receive floating rate cumulative cash dividends, as and when declared by the Board of Directors of the Corporation, 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%. The holders of First Preference Shares, Series L and Series N will be entitled to receive floating rate cumulative cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate of the First Preference Shares, Series L and Series N 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% and 2.48%, respectively.

On or after specified dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole at any time or in part from time to time, at specified fixed prices per share plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.

21. ACCUMULATED OTHER COMPREHENSIVE INCOME

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive income by category is provided as follows.

	2015		
(in millions)	**Opening balance January 1**	**Net change**	**Ending balance December 31**
Net unrealized foreign currency translation gains (losses):			
Unrealized foreign currency translation gains on net investments in foreign operations	**$ 273**	**$ 1,008**	**$ 1,281**
Losses on hedges of net investments in foreign operations	**(131)**	**(345)**	**(476)**
Income tax recovery	**2**	**(1)**	**1**
	144	**662**	**806**
Available-for-sale investment: *(Notes 9, 28 and 31)*			
Unrealized losses on available-for-sale investment	**–**	**(2)**	**(2)**
Cash flow hedges: *(Note 31)*			
Net change in fair value of cash flow hedges	**1**	**2**	**3**
Income tax expense	**–**	**(1)**	**(1)**
	1	**1**	**2**
Unrealized employee future benefits (losses) gains: *(Note 27)*			
Unamortized past service costs	**(2)**	**1**	**(1)**
Unamortized net actuarial losses	**(20)**	**–**	**(20)**
Income tax recovery	**6**	**–**	**6**
	(16)	**1**	**(15)**
Accumulated other comprehensive income	**$ 129**	**$ 662**	**$ 791**

(in millions)	2014 Opening balance January 1	Net change	Ending balance December 31
Net unrealized foreign currency translation (losses) gains:			
Unrealized foreign currency translation (losses) gains on net investments in foreign operations	$ (60)	$ 333	$ 273
Losses on hedges of net investments in foreign operations	–	(131)	(131)
Income tax recovery	–	2	2
	(60)	204	144
Cash flow hedges: *(Note 31)*			
Net change in fair value of cash flow hedges	–	1	1
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	(1)	1	–
Unrealized employee future benefits (losses) gains: *(Note 27)*			
Unamortized past service costs	(3)	1	(2)
Unamortized net actuarial losses	(9)	(11)	(20)
Income tax recovery	1	5	6
	(11)	(5)	(16)
Accumulated other comprehensive (loss) income	$ (72)	$ 201	$ 129

22. NON-CONTROLLING INTERESTS

(in millions)	2015	2014
Waneta Partnership	**$ 335**	$ 316
Caribbean Utilities	**122**	88
Mount Hayes Limited Partnership	**10**	11
Preference shares of Newfoundland Power	**6**	6
	$ 473	$ 421

23. STOCK-BASED COMPENSATION PLANS

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2015, the Corporation had the following stock option plans: the 2012 Plan, the 2006 Plan and the 2002 Plan. The 2012 Plan was approved at the May 4, 2012 Annual General Meeting and will ultimately replace the 2002 and 2006 Plans. The 2002 and 2006 Plans will cease to exist when all outstanding options are exercised or expire in or before 2016 and 2018, respectively. The Corporation has ceased the granting of options under the 2002 and 2006 Plans and all new options granted after 2011 are being made under the 2012 Plan. Directors are not eligible to receive grants of options under the 2012 Plan.

Options granted under the 2006 Plan are exercisable for a period not to exceed seven years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

Options granted under the 2012 Plan are exercisable for a period not to exceed ten years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

For the years ended December 31, 2015 and 2014

23. STOCK-BASED COMPENSATION PLANS (cont'd)

Stock Options (cont'd)

The following options were granted in 2015 and 2014. The fair values of the options were estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

	2015		2014	
	March	August	June	February
Options granted (#)	**667,244**	12,216	23,584	925,172
Exercise price *($)* [(1)]	**39.25**	33.44	32.23	30.73
Grant date fair value *($)*	**2.46**	2.47	2.69	3.53
Assumptions:				
Dividend yield *(%)* [(2)]	**3.6**	3.8	3.8	3.8
Expected volatility *(%)* [(3)]	**14.6**	15.7	15.9	20.3
Risk-free interest rate *(%)* [(4)]	**0.90**	1.45	1.52	1.69
Weighted average expected life *(years)* [(5)]	**5.5**	5.5	5.5	5.5

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

The Corporation records compensation expense upon the issuance of stock options granted under its 2002, 2006 and 2012 Plans. Using the fair value method, each grant is treated as a single award, the fair value of which is amortized to compensation expense evenly over the four-year vesting period of the options.

The following table summarizes information related to stock options for 2015.

	Total Options		**Non-vested Options** [(1)]	
	Number of Options	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Grant Date Fair Value**
Options outstanding, January 1, 2015	**4,705,935**	**$ 30.27**	**2,148,380**	**$ 3.84**
Granted	**667,244**	**$ 39.25**	**667,244**	**$ 2.46**
Exercised	**(885,242)**	**$ 27.55**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(828,547)**	**$ 4.01**
Cancelled/Forfeited	**(71,483)**	**$ 33.16**	**(50,545)**	**$ 3.49**
Options outstanding, December 31, 2015	**4,416,454**	**$ 32.12**	**1,936,532**	**$ 3.30**
Options vested, December 31, 2015 [(2)]	**2,479,922**	**$ 30.22**		

(1) As at December 31, 2015, there was $6 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.
(2) As at December 31, 2015, the weighted average remaining term of vested options was four years with an aggregate intrinsic value of $18 million.

The following table summarizes additional 2015 and 2014 stock option information.

(in millions)	**2015**	2014
Stock option expense recognized	**$ 3**	$ 3
Stock options exercised:		
Cash received for exercise price	**24**	36
Intrinsic value realized by employees	**10**	12
Fair value of options that vested	**3**	3

Directors' DSU Plan

Under the Corporation's Directors' DSU Plan, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation. In addition, directors can elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of DSUs	**2015**	2014
DSUs outstanding, beginning of year	**176,124**	203,172
Granted	**28,737**	29,279
Granted – notional dividends reinvested	**7,037**	8,526
DSUs paid out	**(44,136)**	(64,853)
DSUs outstanding, end of year	**167,762**	176,124

For the year ended December 31, 2015, expense of $1 million (2014 – $3 million) was recognized in earnings with respect to the DSU Plan.

In 2015, 44,136 DSUs were paid out to retired and deceased directors at a weighted average price of $37.58 per DSU for a total of approximately $2 million.

As at December 31, 2015, the liability related to outstanding DSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2015 of $37.72, for a total of $6 million (December 31, 2014 – $7 million), and is included in long-term other liabilities (Note 17).

PSU Plans

The Corporation's PSU Plans represent a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. As at December 31, 2015, the Corporation had the following PSU plans: the 2013 PSU Plan, the 2015 PSU Plan, and certain subsidiaries of the Corporation have also adopted similar share unit plans that are modelled after the Corporation's plans. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

The PSUs are subject to a three-year vesting and performance period, at which time a cash payment may be made, as determined by the Human Resources Committee of the Board of Directors. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the VWAP of the Corporation's common shares for five trading days prior to the maturity of the grant and by a payout percentage that may range from 0% to 150%.

The payout percentage for the PSU Plans is based on the Corporation's performance over the three-year period, mainly determined by: (i) the Corporation's total shareholder return as compared to a pre-defined peer group of companies; and (ii) the Corporation's cumulative compound annual growth rate in earnings per common share or, for certain subsidiaries, the Company's cumulative net income, as compared to the target established at the time of the grant. As at December 31, 2015, the estimated payout percentages for the grants under the 2013 and 2015 PSU Plans range from 96% to 118%.

The following table summarizes information related to the PSUs for 2015 and 2014.

Number of PSUs	**2015**	2014
PSUs outstanding, beginning of year	**481,700**	257,419
Granted	**276,381**	261,737
Granted – notional dividends reinvested	**25,687**	17,691
PSUs paid out	**(83,637)**	(33,559)
PSUs cancelled/forfeited	**(5,745)**	(21,588)
PSUs outstanding, end of year	**694,386**	481,700

In January 2015, 68,759 PSUs were paid out to the former Chief Executive Officer ("CEO") of the Corporation at $38.90 per PSU, for a total of approximately $3 million. The payout was made in respect of the PSU grant made in March 2012 and the former CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors. As a result of the sale of commercial real estate and hotel assets, in October 2015, 14,878 PSUs were paid out to certain employees at a 100% payout percentage under the 2013 PSU Plan and the 2015 PSU Plan at $38.48 per PSU, for a total of approximately $1 million.

23. STOCK-BASED COMPENSATION PLANS (cont'd)

PSU Plans (cont'd)

For the year ended December 31, 2015, expense of approximately $12 million (2014 – $7 million) was recognized in earnings with respect to the PSU Plans and there was $9 million of unrecognized compensation expense related to PSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2015, the aggregate intrinsic value of the outstanding PSUs was $28 million, with a weighted average contractual life of approximately one year. The liability related to outstanding PSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2015 of $37.72, for a total of $19 million (December 31, 2014 – $10 million), and is included in accounts payable and other current liabilities and long-term other liabilities (Notes 14 and 17).

RSU Plans

In February 2015 the Corporation's Board of Directors approved the 2015 RSU Plan, effective January 1, 2015. The Corporation's 2015 RSU Plan represents a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. Each RSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period, at which time a cash payment may be made. Each RSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of RSUs	**2015**
Granted	**59,462**
Granted – notional dividends reinvested	**2,150**
RSUs cancelled/forfeited	**(2,872)**
RSUs outstanding, end of year	**58,740**

For the year ended December 31, 2015, expense of approximately $1 million was recognized in earnings with respect to the RSU Plan and there was approximately $1 million of unrecognized compensation expense related to RSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2015, the liability related to outstanding RSUs was recorded at the VWAP of the Corporation's common shares for the last five trading days of 2015 of $37.72, for a total of $1 million, and is included in long-term other liabilities (Note 17).

24. OTHER INCOME (EXPENSES), NET

(in millions)	**2015**	2014
Net gain on sale of commercial real estate and hotel assets *(Note 28)* [(1)]	**$ 109**	$ –
Gain on sale of non-regulated generation assets *(Note 28)* [(2)]	**56**	–
Equity component of AFUDC	**23**	11
Net foreign exchange gain	**13**	8
Interest income	**8**	13
Loss on settlement of expropriation matters *(Note 9)*	**(9)**	–
Acquisition-related expenses *(Notes 29 and 35)*	**(10)**	(25)
Acquisition-related customer and community benefits *(Notes 8 (xvii) and 29)*	**–**	(33)
Other	**(3)**	1
	$ 187	$ (25)

[(1)] Net of $23 million of expenses associated with the sale
[(2)] Net of $6 million of expenses and foreign exchange impacts associated with the sale

The net foreign exchange gain relates to the translation into Canadian dollars of the Corporation's previous US dollar-denominated long-term other asset, representing the book value of the Corporation's expropriated investment in Belize Electricity, up to the date of settlement of expropriation matters in August 2015 (Note 9). As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015. Unrealized foreign exchange gains and losses associated with the Corporation's 33% equity investment in Belize Electricity are recognized on the balance sheet in accumulated other comprehensive income.

The acquisition-related expenses and customer and community benefits in 2014 were associated with the acquisition of UNS Energy (Note 29).

25. FINANCE CHARGES

(in millions)	**2015**	2014
Interest – Long-term debt and capital lease and finance obligations	**$ 572**	$ 482
– Short-term borrowings	**8**	20
– Convertible Debentures *(Note 18)*	**–**	72
Debt component of AFUDC	**(27)**	(27)
	$ 553	$ 547

26. INCOME TAXES

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. The significant components of deferred income tax assets and liabilities consist of the following.

(in millions)	**2015**	2014
Gross deferred income tax assets		
Tax loss and credit carryforwards	**$ 387**	$ 376
Regulatory liabilities	**210**	186
Employee future benefits	**116**	108
Share issue and debt financing costs	**13**	20
Unrealized foreign exchange losses on long-term debt	**65**	17
Other	**45**	70
	836	777
Deferred income tax assets valuation allowance	**(73)**	(24)
Net deferred income tax assets	**$ 763**	$ 753
Gross deferred income tax liabilities		
Utility capital assets	**$ (2,575)**	$ (2,096)
Regulatory assets	**(201)**	(204)
Non-utility capital assets	**–**	(40)
Intangible assets	**(37)**	(39)
	(2,813)	(2,379)
Net deferred income tax liability	**$ (2,050)**	$ (1,626)

The deferred income tax asset associated with unrealized foreign exchange losses on long-term debt reflects $65 million of capital losses as at December 31, 2015 (December 31, 2014 – $17 million). The deferred income tax asset can only be used if the Corporation has capital gains to offset the losses. Management believes that it is more likely than not that Fortis will not be able to generate future capital gains and, as a result, the Corporation recorded a $65 million valuation allowance against the deferred income tax asset as at December 31, 2015 (December 31, 2014 – $17 million). Management believes that based on its historical pattern of taxable income, Fortis will produce sufficient income in the future to realize all other deferred income tax assets.

For the years ended December 31, 2015 and 2014

26. INCOME TAXES (cont'd)

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2015 and 2014.

(in millions)	2015	2014
Total unrecognized tax benefits, beginning of year	**$ 11**	$ 3
Additions related to the current year	**1**	7
Adjustments related to prior years	**1**	1
Total unrecognized tax benefits, end of year	**$ 13**	$ 11

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2015. Fortis has not recognized interest expense in 2015 and 2014 related to unrecognized tax benefits.

The components of the income tax expense were as follows.

(in millions)	2015	2014
Canadian		
Current income taxes	**$ 59**	$ 43
Deferred income taxes	**113**	64
Less: regulatory adjustments	**(100)**	(67)
	13	(3)
Total Canadian	**$ 72**	$ 40
Foreign		
Deferred income taxes	**151**	26
Total Foreign	**$ 151**	$ 26
Income tax expense	**$ 223**	$ 66

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

(in millions, except as noted)	2015	2014
Combined Canadian federal and provincial statutory income tax rate	**27.5%**	29.0%
Statutory income tax rate applied to earnings before income taxes	**$ 292**	$ 131
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(7)**	(23)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**(4)**	(10)
Items capitalized for accounting purposes but expensed for income tax purposes	**(39)**	(26)
Difference between gain on sale of assets for accounting and amounts calculated for tax purposes	**(18)**	–
Change in tax rates and legislation	**13**	–
Other	**(14)**	(6)
Income tax expense	**$ 223**	$ 66
Effective tax rate	**21.0%**	14.6%

In 2015 the Corporation's combined Canadian federal and provincial statutory income tax rate decreased from 29.0% to 27.5%. This change resulted from the inclusion of the Waneta Partnership's taxable income, which is taxable in the province of British Columbia at a lower provincial income tax rate, and increased income tax expense by approximately $3 million in 2015, through the re-measurement of deferred income tax assets. In addition, a change in New York State tax legislation in 2015 resulted in the need to include UNS Energy as part of the combined New York State tax return. As a result, existing deferred income tax balances were adjusted to reflect the effect of the change in the tax law, resulting in an increase in income tax expense of approximately $10 million in 2015.

As at December 31, 2015, the Corporation had the following tax carryforward amounts.

(in millions)	Expiring Year	**Amount**
Canadian		
Capital loss	n/a	**$ 15**
Non-capital loss	2025 – 2035	**129**
Other tax credits	2026 – 2035	**2**
		146
Unrecognized in the consolidated financial statements		**(15)**
		$ 131
Foreign		
Capital loss	2017	**$ 12**
Federal and state net operating loss	2031 – 2034	**653**
Other tax credits	2016 – 2035	**69**
Alternative minimum tax credits	n/a	**64**
		798
Unrecognized in the consolidated financial statements		**(17)**
		781
Total tax carryforwards		**$ 912**

As at December 31, 2015, the Corporation had approximately $912 million in tax carryforward amounts recognized in the consolidated financial statements (December 31, 2014 – $1,093 million).

The Corporation and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential examinations include the United States (Federal, Arizona and New York) and Canada (Federal and British Columbia). The Corporation's 2010 to 2015 taxation years are still open for audit in the Canadian jurisdictions and 2011 to 2015 taxation years are still open for audit in the United States jurisdictions. The Corporation is not currently under examination for income tax matters in any of these jurisdictions.

27. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans, and OPEB plans. For the defined benefit pension and OPEB plan arrangements, the benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year.

Actuarial valuations are required to determine funding contributions for pension plans, at least, every three years for Fortis' Canadian and Caribbean subsidiaries. The most recent valuations were as of December 31, 2012 for FortisBC Energy (plan covering non-unionized employees), FortisAlberta and Caribbean Utilities; December 31, 2013 for FortisBC Electric and FortisBC Energy (plans covering unionized employees); as of December 31, 2014 for Newfoundland Power, FortisOntario, and the Corporation.

UNS Energy and Central Hudson perform annual actuarial valuations, as their funding contribution requirements are based on maintaining annual target fund percentages. Both UNS Energy and Central Hudson have met the minimum funding requirements.

For the years ended December 31, 2015 and 2014

27. EMPLOYEE FUTURE BENEFITS (cont'd)

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

The Corporation's consolidated defined benefit pension and OPEB plan weighted average asset allocations were as follows.

Plan assets as at December 31 *(%)*	**2015 Target Allocation**	**2015**	2014
Equities	**50**	**51**	49
Fixed income	**46**	**44**	46
Real estate	**4**	**4**	4
Cash and other	**–**	**1**	1
	100	**100**	100

The fair value measurements of defined benefit pension and OPEB plan assets by fair value hierarchy, as defined in Note 31, were as follows.

Fair value of plan assets as at December 31, 2015

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Equities	**$ 417**	**$ 922**	**$ –**	**$ 1,339**
Fixed income	**–**	**1,166**	**–**	**1,166**
Real estate	**–**	**14**	**97**	**111**
Private equities	**–**	**–**	**10**	**10**
Cash and other	**3**	**18**	**–**	**21**
	$ 420	**$ 2,120**	**$ 107**	**$ 2,647**

Fair value of plan assets as at December 31, 2014

(in millions)	Level 1	Level 2	Level 3	Total
Equities	$ 352	$ 806	$ –	$ 1,158
Fixed income	23	1,069	–	1,092
Real estate	–	11	85	96
Private equities	–	–	8	8
Cash and other	6	10	–	16
	$ 381	$ 1,896	$ 93	$ 2,370

The following table is a reconciliation of changes in the fair value of pension plan assets that have been measured using Level 3 inputs for the years ended December 31, 2015 and 2014.

(in millions)	**2015**	2014
Balance, beginning of year	**$ 93**	$ 62
Assets assumed on acquisition	**–**	24
Actual return on plan assets held at end of year	**9**	6
Foreign currency translation impacts	**5**	–
Purchases, sales and settlements	**–**	1
Balance, end of year	**$ 107**	$ 93

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension and OPEB plans and their respective funded status.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Change in benefit obligation [1]				
Balance, beginning of year	**$ 2,604**	$ 1,724	**$ 564**	$ 417
Liabilities assumed on acquisition	**–**	403	**–**	83
Service costs	**68**	43	**17**	11
Employee contributions	**17**	17	**1**	1
Interest costs	**109**	90	**23**	21
Benefits paid	**(118)**	(101)	**(21)**	(15)
Actuarial (gains) losses	**(102)**	335	**(50)**	27
Past service credits/plan amendments	**–**	–	**(10)**	–
Foreign currency translation impacts	**250**	93	**50**	19
Balance, end of year [2]	**$ 2,828**	$ 2,604	**$ 574**	$ 564
Change in value of plan assets				
Balance, beginning of year	**$ 2,216**	$ 1,541	**$ 154**	$ 121
Assets assumed on acquisition	**–**	373	**–**	13
Actual return on plan assets	**30**	236	**–**	11
Benefits paid	**(118)**	(101)	**(21)**	(15)
Employee contributions	**17**	17	**1**	1
Employer contributions	**99**	70	**17**	11
Foreign currency translation impacts	**222**	80	**30**	12
Balance, end of year	**$ 2,466**	$ 2,216	**$ 181**	$ 154
Funded status	**$ (362)**	$ (388)	**$ (393)**	$ (410)

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

(2) The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $2,595 million as at December 31, 2015 (December 31, 2014 – $2,378 million).

The following table summarizes the employee future benefit assets and liabilities and their classifications on the consolidated balance sheet.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Assets				
Defined benefit pension assets:				
Long-term other assets	**$ 11**	$ 6	**$ –**	$ –
Liabilities				
Defined benefit pension liabilities:				
Current *(Note 14)*	**5**	4	**–**	–
Long-term other liabilities *(Note 17)*	**368**	390	**–**	–
OPEB plan liabilities:				
Current *(Note 14)*	**–**	–	**8**	7
Long-term other liabilities *(Note 17)*	**–**	–	**385**	403
Net liabilities	**$ 362**	$ 388	**$ 393**	$ 410

For the years ended December 31, 2015 and 2014

27. EMPLOYEE FUTURE BENEFITS (cont'd)

The net benefit cost for the Corporation's defined benefit pension plans and OPEB plans were as follows:

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Components of net benefit cost				
Service costs	**$ 68**	$ 43	**$ 17**	$ 11
Interest costs	**109**	90	**23**	21
Expected return on plan assets	**(140)**	(106)	**(12)**	(9)
Amortization of actuarial losses	**57**	32	**5**	3
Amortization of past service credits/plan amendments	**–**	(1)	**(5)**	(3)
Amortization of transitional obligation (asset)	**2**	2	**(7)**	(6)
Regulatory adjustments	**1**	11	**6**	4
Net benefit cost	**$ 97**	$ 71	**$ 27**	$ 21

The following tables provide the components of accumulated other comprehensive loss and regulatory assets and liabilities, which would otherwise have been recognized as accumulated other comprehensive loss, for the years ended December 31, 2015 and 2014 that have not been recognized as components of net benefit cost.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Unamortized net actuarial losses	**$ 16**	$ 16	**$ 4**	$ 4
Unamortized past service costs	**1**	–	**–**	2
Income tax recovery	**(5)**	(5)	**(1)**	(1)
Accumulated other comprehensive loss *(Note 21)*	**$ 12**	$ 11	**$ 3**	$ 5
Net actuarial losses	**$ 513**	$ 513	**$ 41**	$ 95
Past service credits	**–**	–	**(33)**	(43)
Amount deferred due to actions of regulators	**23**	18	**39**	39
	$ 536	$ 531	**$ 47**	$ 91
Regulatory assets *(Note 8 (ii))*	**$ 536**	$ 531	**$ 91**	$ 149
Regulatory liabilities *(Note 8 (ii))*	**–**	–	**(44)**	(58)
Net regulatory assets	**$ 536**	$ 531	**$ 47**	$ 91

The following tables provide the components recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Current year net actuarial losses (gains)	**$ –**	$ 9	**$ (1)**	$ 3
Past service credits/plan amendments	**–**	–	**(1)**	(1)
Amortization of actuarial gains (losses)	**1**	(1)	**–**	–
Income tax recovery	**–**	(4)	**–**	(1)
Total recognized in comprehensive income	**$ 1**	$ 4	**$ (2)**	$ 1
Assets assumed on acquisition	**$ –**	$ 79	**$ –**	$ 6
Current year net actuarial losses (gains)	**8**	197	**(28)**	23
Past service credits/plan amendments	**–**	–	**(10)**	–
Amortization of actuarial losses	**(56)**	(31)	**(5)**	(5)
Amortization of past service costs	**(1)**	(1)	**(2)**	(3)
Foreign currency translation impacts	**49**	14	**(6)**	(4)
Regulatory adjustments	**5**	(37)	**7**	(1)
Total recognized in regulatory assets	**$ 5**	$ 221	**$ (44)**	$ 16

Net actuarial losses of $1 million are expected to be amortized from accumulated other comprehensive income into net benefit cost in 2016 related to defined benefit pension plans.

Net actuarial losses of $47 million, past service credits of $1 million and regulatory adjustments of $2 million are expected to be amortized from regulatory assets into net benefit cost in 2016 related to defined benefit pension plans. Net actuarial losses of $3 million, past service credits of $1 million and regulatory adjustments of $5 million are expected to be amortized from regulatory assets into net benefit cost in 2016 related to OPEB plans.

Significant weighted average assumptions	**Defined Benefit Pension Plans**		**OPEB Plans**	
(%)	**2015**	2014	**2015**	2014
Discount rate during the year	**4.00**	4.81	**3.95**	4.72
Discount rate as at December 31	**4.21**	4.00	**4.12**	3.95
Expected long-term rate of return on plan assets (1)	**6.25**	6.46	**6.95**	7.08
Rate of compensation increase	**3.48**	3.48	**–**	–
Health care cost trend increase as at December 31 (2)	**–**	–	**4.67**	4.67

(1) Developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

(2) The projected 2016 weighted average health care cost trend rate is 6.98% for OPEB plans and is assumed to decrease over the next 13 years by 2028 to the weighted average ultimate health care cost trend rate of 4.67% and remain at that level thereafter.

For 2015 the effects of changing the health care cost trend rate by 1% were as follows.

(in millions)	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in accumulated benefit obligation	**$ 51**	**$ (43)**
Increase (decrease) in service and interest costs	**5**	**(3)**

The following table provides the amount of benefit payments expected to be made over the next 10 years.

Year	**Defined Benefit Pension Payments** *(in millions)*	**OPEB Payments** *(in millions)*
2016	$ 122	$ 24
2017	127	26
2018	131	27
2019	136	29
2020	141	30
2021 – 2025	796	173

Refer to Note 33 for expected defined benefit pension and OPEB plan funding contributions.

During 2015 the Corporation expensed $28 million (2014 – $21 million) related to defined contribution pension plans.

28. DISPOSITIONS AND DISCONTINUED OPERATIONS

Sale of Commercial Real Estate and Hotel Assets

In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million. As a result of the sale, the Corporation recognized a gain on sale of $129 million ($109 million after tax), net of expenses (Note 24). As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering (Notes 9 and 31).

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As a result of the sale, the Corporation recognized a loss of approximately $20 million ($8 million after tax), which reflects an impairment loss and expenses associated with the sale transaction (Note 24).

28. DISPOSITIONS AND DISCONTINUED OPERATIONS (cont'd)

Sale of Commercial Real Estate and Hotel Assets (cont'd)

Net proceeds from the sales were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy (Note 29), and for other general corporate purposes.

Earnings before taxes related to Fortis Properties of approximately $18 million were recognized in 2015, excluding the net gain on sale, compared to $31 million in 2014.

Sale of Non-Regulated Generation Assets in New York and Ontario

In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized a gain on sale of $51 million (US$41 million) ($27 million (US$22 million) after tax), net of expenses and foreign exchange impacts (Note 24).

In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of approximately $16 million. As a result of the sale, the Corporation recognized a gain on sale of $5 million ($5 million after tax) (Note 24).

Earnings before taxes of less than $1 million were recognized in 2015, excluding the gain on sale, compared to $3 million in 2014.

Sale of Griffith

In March 2014 Griffith was sold for proceeds of approximately $105 million (US$95 million). The results of operations to the date of sale are presented as discontinued operations on the consolidated statements of earnings. As a result of the disposal, earnings from discontinued operations of $8 million ($5 million after tax) were recognized in the first quarter of 2014.

29. BUSINESS ACQUISITIONS

2015

Pending Acquisition of Aitken Creek Gas Storage Facility

In December 2015 Fortis, through an indirect wholly owned subsidiary, entered into a definitive share purchase and sale agreement with Chevron Canada Properties Ltd. to acquire its shares of the Aitken Creek Gas Storage Facility ("Aitken Creek") for approximately US$266 million, subject to customary closing conditions and adjustments. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada's natural gas transmission network. The acquisition is subject to regulatory approval and is expected to close in the first half of 2016. The net cash purchase price is expected to be initially financed with borrowings under the Corporation's credit facility. In December 2015 the Corporation paid a deposit of US$29 million related to the transaction, which is included in long-term other assets on the consolidated balance sheet (Note 9).

2014

UNS Energy

On August 15, 2014, Fortis acquired all of the outstanding common shares of UNS Energy for US$60.25 per common share in cash, for an aggregate purchase price of approximately US$4.5 billion, including the assumption of US$2.0 billion of debt on closing.

Financing of the net cash purchase price of approximately $2.7 billion (US$2.5 billion) is complete. Fortis completed the sale of $1.8 billion 4% Convertible Debentures. Proceeds from the first installment of approximately $599 million were received in January 2014. A significant portion of these cash proceeds were used to finance a portion of the UNS Energy acquisition. Proceeds from the final installment of approximately $1.2 billion were received on October 28, 2014 and were used to repay borrowings under acquisition credit facilities initially used to finance a portion of the UNS Energy acquisition. Substantially all of the Convertible Debentures have been converted into approximately 58.6 million common shares of Fortis (Note 18). In September 2014 Fortis issued 24 million 4.1% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M for gross proceeds of $600 million (Note 20). The net proceeds were also used to repay a portion of borrowings under the acquisition credit facilities. The remainder of the purchase price was financed through credit facility borrowings under a medium-term bridge facility and the Corporation's revolving credit facility (Note 32), which were subsequently repaid using net proceeds from the sale of commercial real estate and hotel assets (Note 28).

UNS Energy's operations are regulated by the ACC and FERC (Note 2). The determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change of ownership. No fair value adjustments, other than goodwill, were recorded for the net assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers.

The following table summarizes the final allocation of the purchase consideration to the assets and liabilities acquired as at August 15, 2014, based on their fair values, using an exchange rate of US$1.00=CAD$1.0925.

(in millions)	Total
Purchase consideration	**$ 2,745**
Fair value assigned to net assets:	
Current assets	**539**
Long-term regulatory assets	**185**
Utility capital assets	**3,972**
Intangible assets	**116**
Other long-term assets	**108**
Current liabilities	**(458)**
Assumed long-term debt and capital lease and finance obligations (including current portion)	**(2,186)**
Long-term regulatory liabilities	**(341)**
Other long-term liabilities	**(797)**
	1,138
Cash and cash equivalents	**97**
Fair value of net assets acquired	**1,235**
Goodwill *(Note 13)*	**$ 1,510**

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on August 15, 2014.

In 2014 acquisition-related expenses of approximately $25 million ($19 million after tax) were recognized in other income (expenses), net on the consolidated statement of earnings (Note 24). In addition, approximately $33 million (US$30 million), or $20 million (US$18 million) after tax, in customer benefits offered to obtain regulatory approval of the acquisition were expensed in 2014 and were also recognized in other income (expenses), net on the consolidated statement of earnings (Notes 8 *(xvii)* and 24).

30. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	2015	2014
Cash paid for:		
Interest	**$ 561**	$ 538
Income taxes	**109**	83
Change in non-cash operating working capital:		
Accounts receivable and other current assets	**$ 14**	$ 53
Prepaid expenses	**(1)**	2
Inventories	**15**	(11)
Regulatory assets – current portion	**57**	(16)
Accounts payable and other current liabilities	**(82)**	(123)
Regulatory liabilities – current portion	**38**	(29)
	$ 41	$ (124)
Non-cash investing and financing activities:		
Common share dividends reinvested	**$ 156**	$ 81
Conversion of Convertible Debentures into common shares *(Note 18)*	**1**	1,747
Additions to utility capital assets, non-utility capital assets, and intangible assets included in current and long-term liabilities	**187**	200
Contributions in aid of construction included in current assets	**4**	7
Exercise of stock options into common shares	**4**	5

31. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets;
Level 2: Fair value determined using pricing inputs that are observable; and
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

(in millions)	**Fair value hierarchy**	**As at December 31**	
		2015	2014
Assets			
Energy contracts subject to regulatory deferral [(1) (2) (3)]	Levels 2/3	**$ 7**	$ 3
Energy contracts not subject to regulatory deferral [(1) (2)]	Level 3	**2**	1
Available-for-sale investment *(Note 9)* [(4) (5)]	Level 1	**33**	–
Assets held for sale *(Note 6)*	Level 2	**9**	–
Other investments [(4)]	Level 1	**12**	5
Total gross assets		**63**	9
Less: Counterparty netting not offset on the balance sheet [(6)]		**(6)**	(3)
Total net assets		**$ 57**	$ 6
Liabilities			
Energy contracts subject to regulatory deferral [(1) (2) (7)]	Levels 1/2/3	**$ 78**	$ 72
Energy contracts not subject to regulatory deferral [(1) (2)]	Level 3	**–**	1
Energy contracts – cash flow hedges [(2) (8)]	Level 3	**–**	1
Interest rate swaps – cash flow hedges [(8)]	Level 2	**5**	5
Total gross liabilities		**83**	79
Less: Counterparty netting not offset on the balance sheet [(6)]		**(6)**	(3)
Total net liabilities		**$ 77**	$ 76

(1) The fair value of the Corporation's energy contracts is recorded in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in rates as permitted by the regulators, with the exception of long-term wholesale trading contracts.
(2) Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and those that qualify as cash flow hedges.
(3) Includes $2 million – level 2 and $5 million – level 3 (2014 – $3 million – level 3)
(4) Included in long-term other assets on the consolidated balance sheet
(5) The cost of the available-for-sale investment was $35 million and unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings (Notes 9 and 28).
(6) Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.
(7) Includes $1 million – level 1, $52 million – level 2 and $25 million – level 3 (2014 – $2 million – level 1, $35 million – level 2 and $35 million – level 3)
(8) The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships and transmission and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

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

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

As at December 31, 2015, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recorded in earnings. As at December 31, 2015, unrealized losses of $74 million (December 31, 2014 – $69 million) were recognized in regulatory assets and unrealized gains of $3 million were recognized in regulatory liabilities (Note 8 *(vii)*).

Energy Contracts Not Subject to Regulatory Deferral

In June 2015 UNS Energy entered into long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with the ratepayer through UNS Energy's rate stabilization accounts.

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on lease debt, and held a power purchase swap, that expired in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $1 million.

Central Hudson holds interest rate cap contracts expiring in 2016 and 2017 on bonds with a total principal amount of US$64 million. Variations in the interest costs of the bonds, including any gains or losses associated with the interest rate cap contracts, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator and do not impact earnings.

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

For the years ended December 31, 2015 and 2014

31. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Volume of Derivative Activity

As at December 31, 2015, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity *(year)*	Contracts *(#)*	2016	2017	2018	2019	2020	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts (gigawatt hours *("GWh")*)	2019	8	1,043	730	438	219	–	–
Electricity power purchase contracts *(GWh)*	2017	28	1,027	145	–	–	–	–
Gas swap and option contracts (petajoules *("PJ")*)	2018	154	40	10	4	–	–	–
Gas purchase contract premiums *(PJ)*	2024	89	91	42	38	22	22	64
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2016	6	1,310	–	–	–	–	–

Financial Instruments Not Carried At Fair Value

The following table discloses the estimated fair value measurements of the Corporation's financial instruments not carried at fair value. The fair values were measured using Level 2 pricing inputs, except as noted. The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows:

	As at			
Asset (Liability)	**December 31, 2015**		December 31, 2014	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term other asset – Belize Electricity [(1)]	**$ –**	**$ –**	$ 116	$ n/a
Long-term debt, including current portion *(Note 15)* [(2)]	**(11,240)**	**(12,614)**	(10,501)	(12,237)
Waneta Partnership promissory note *(Note 17)*	**(56)**	**(59)**	(53)	(56)

(1) In August 2015 the Corporation settled expropriation matters with the GOB regarding the GOB's expropriation of Belize Electricity (Note 9).

(2) The Corporation's $200 million unsecured debentures due 2039 and consolidated borrowings under credit facilities classified as long-term debt of $551 million (December 31, 2014 – $1,096 million) are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.

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

32. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash equivalents, trade and other accounts receivable, and long-term other receivables, the Corporation's credit risk is generally limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at December 31, 2015, FortisAlberta's gross credit risk exposure was approximately $116 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to $3 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson and FortisBC Energy may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Companies use netting arrangements to reduce credit risk and net settle payments with counterparties where net settlement provisions exist. They also limit credit risk by only dealing with counterparties that have investment-grade credit ratings. At UNS Energy, contractual arrangements also contain certain provisions requiring counterparties to derivative instruments to post collateral under certain circumstances.

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's committed corporate credit facility is used for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at December 31, 2015, over the next five years, average annual consolidated fixed-term debt maturities and repayments are expected to be approximately $260 million. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at December 31, 2015, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.6 billion, of which approximately $2.4 billion was unused, including $570 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, as well as large banks in the United States, with no one bank holding more than 20% of these facilities. Approximately $3.3 billion of the total credit facilities are committed facilities with maturities ranging from 2016 through 2020.

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

(in millions)	Regulated Utilities	Corporate and Other	**Total as at December 31, 2015**	Total as at December 31, 2014
Total credit facilities [(1)]	$ 2,211	$ 1,354	**$ 3,565**	$ 3,854
Credit facilities utilized:				
Short-term borrowings [(2)]	(511)	–	**(511)**	(330)
Long-term debt *(Note 15)* [(3)]	(71)	(480)	**(551)**	(1,096)
Letters of credit outstanding	(68)	(36)	**(104)**	(192)
Credit facilities unused	$ 1,561	$ 838	**$ 2,399**	$ 2,236

(1) Total credit facilities exclude a $300 million option to increase the Corporation's committed corporate credit facility, as discussed below.

(2) The weighted average interest rate on short-term borrowings was approximately 1.0% as at December 31, 2015 (December 31, 2014 – 1.3%).

(3) As at December 31, 2015, credit facility borrowings classified as long-term debt included $71 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2014 – $257 million). The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 1.5% as at December 31, 2015 (December 31, 2014 – 1.8%).

32. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

As at December 31, 2015 and 2014, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities
The UNS Utilities have a total of US$350 million ($484 million) in unsecured committed revolving credit facilities maturing in October 2020, with the option of two one-year extensions.

Central Hudson has a US$200 million ($277 million) unsecured committed revolving credit facility, maturing in October 2020, that is utilized to finance capital expenditures and for general corporate purposes. Central Hudson also has an uncommitted credit facility totalling US$25 million ($34 million).

FEI has a $700 million unsecured committed revolving credit facility, maturing in August 2018, that is utilized to finance working capital requirements, capital expenditures and for general corporate purposes.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2020, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2018. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2019, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2016.

Caribbean Utilities has unsecured credit facilities totalling approximately US$47 million ($65 million). Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$26 million ($36 million), maturing in September 2016.

Corporate and Other
Fortis has a $1 billion unsecured committed revolving 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 at December 31, 2015, the Corporation has not yet exercised its option for the additional $300 million. The Corporation also has a $35 million letter of credit facility, maturing in January 2017.

UNS Energy Corporation has a US$150 million ($208 million) unsecured committed revolving credit facility, maturing in October 2020, with the option of two one-year extensions.

CH Energy Group has a US$50 million ($69 million) unsecured committed revolving credit facility, maturing in July 2020, that can be utilized for general corporate purposes.

FHI has a $30 million unsecured committed revolving credit facility, maturing in April 2018, that is available for general corporate purposes.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2015, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A– / Stable (long-term corporate and unsecured debt credit rating)
DBRS	A (low) / Stable (unsecured debt credit rating)

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining reasonable levels of debt at the holding company level. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC Holdings Corp. ("ITC") (Note 35), S&P affirmed the Corporation's long-term corporate credit rating at A–, revised its unsecured debt 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 credit rating under review with negative implications.

Market Risk

Foreign Exchange Risk
The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar.

As at December 31, 2015, the Corporation's corporately issued US$1,535 million (December 31, 2014 – US$1,496 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2015, the Corporation had approximately US$3,137 million (December 31, 2014 – US$2,762 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded on the consolidated balance sheet in accumulated other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded on the consolidated balance sheet in accumulated other comprehensive income.

On an annual basis, it is estimated that a 5 cent, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.38 as at December 31, 2015 would increase or decrease earnings per common share of Fortis by approximately 4 cents. Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Interest Rate Risk
The Corporation and most of its subsidiaries are exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and the refinancing of long-term debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk (Notes 15, 16 and 31).

Commodity Price Risk
UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market price of electricity and natural gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of natural gas. The risks have been reduced by entering into derivative contracts that effectively fix the price of natural gas, power and electricity purchases. These derivative instruments are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, as permitted by the regulators, for recovery from, or refund to, customers in future rates (Note 31).

33. COMMITMENTS

As at December 31, 2015, the Corporation's consolidated commitments in each of the next five years and for periods thereafter, excluding repayments of long-term debt and capital lease and finance obligations separately disclosed in Notes 15 and 16, respectively, are as follows:

($ in millions)	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Interest obligations on long-term debt	**9,435**	536	512	507	495	488	6,897
Renewable power purchase obligations (1)	**1,589**	93	93	92	92	92	1,127
Gas purchase obligations (2)	**1,449**	366	253	222	153	131	324
Power purchase obligations (3)	**1,440**	281	209	180	102	36	632
Long-term contracts – UNS Energy (4)	**1,057**	146	141	105	102	82	481
Capital cost (5)	**488**	19	19	19	19	19	393
Operating lease obligations (6)	**181**	12	11	11	11	8	128
Renewable energy credit purchase agreements (7)	**162**	13	13	13	13	13	97
Purchase of Springerville Common Facilities (8)	**147**	–	53	–	–	–	94
Defined benefit pension and OPEB funding contributions *(Note 27)*	**139**	49	12	8	9	9	52
Waneta Partnership promissory note *(Note 17)*	**72**	–	–	–	–	72	–
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other (9)	**71**	15	12	16	3	–	25
Total	**16,283**	1,533	1,331	1,176	1,002	953	10,288

33. COMMITMENTS (cont'd)

(1) TEP and UNS Electric are party to 20-year long-term renewable PPAs totalling approximately US$1,148 million as at December 31, 2015, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities that have achieved commercial operation. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. These agreements have various expiry dates through 2035. TEP has entered into additional long-term renewable PPAs to comply with renewable energy standards of the State of Arizona; however, the Company's obligation to purchase power under these agreements does not begin until the facilities are operational. In February 2016 one of the generating facilities achieved commercial operation, increasing estimated future payments of renewable PPAs by US$58 million, which is not included in the table above.

(2) Certain of the Corporation's subsidiaries, mainly FortisBC Energy and Central Hudson, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2015. At Central Hudson, the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2015.

(3) Power purchase obligations include various power purchase contracts held by certain of the Corporation's subsidiaries, as described below.

FortisBC Energy

In March 2015 FortisBC Energy entered into an Electricity Supply Agreement with BC Hydro for the purchase of electricity supply to the Tilbury Expansion Project, with purchase obligations totalling $513 million as at December 31, 2015.

FortisBC Electric

Power purchase obligations for FortisBC Electric, totalling $292 million as at December 31, 2015, mainly include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term, as approved by the BCUC. The capacity and energy to be purchased under this agreement do not relate to a specific plant.

In addition, in November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"), allowing FortisBC Electric to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Commitments table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

FortisOntario

Power purchase obligations for FortisOntario, totalling $208 million as at December 31, 2015, primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Quebec Energy Marketing for the supply of electricity and capacity, both expiring in December 2019. 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 provides a minimum of 300 GWh of electricity per contract year.

Maritime Electric

Power purchase obligations for Maritime Electric, totalling $194 million as at December 31, 2015, primarily include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019 and November 2032, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power") expiring in February 2019.

Central Hudson

Central Hudson's power purchase obligations totalled US$124 million as at December 31, 2015. In June 2014 Central Hudson entered into a contract to purchase available installed 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. 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.

(4) UNS Energy has entered into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$440 million, US$261 million and US$63 million, respectively, as at December 31, 2015. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts. As a result of the restructuring of the ownership of the San Juan generating station in January 2016, a new coal supply agreement came into effect under which TEP's minimum purchase obligations are US$137 million, which is not included in the previous table.

[5] Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit.

[6] Operating lease obligations include certain office, warehouse, natural gas T&D asset, rail car, land easement and rights-of-way, and vehicle and equipment leases.

[7] UNS Energy is party to renewable energy credit purchase agreements, totalling approximately US$117 million as at December 31, 2015, to purchase the environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

[8] UNS Energy has entered into a commitment to exercise its fixed-price purchase provision to purchase an undivided 50% leased interest in the Springerville Common Facilities if the lease is not renewed, for a purchase price of US$106 million, with one facility to be acquired in 2017 and the remaining two facilities to be acquired in 2021 (Note 16).

[9] Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including PSU, RSU and DSU Plan obligations and asset retirement obligations.

Other Commitments

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $1.9 billion for 2016. Over the five years 2016 through 2020, the Corporation's consolidated capital expenditure program is expected to be approximately $9 billion, which has not been included in the Commitments table.

Other: 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 totalling 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 a maximum commitment of US$182 million. As at December 31, 2015, no payment obligation is expected under this guarantee.

FortisBC Energy issued commitment letters to customers, totalling $33 million as at December 31, 2015, to provide Energy Efficiency and Conservation ("EEC") funding under the EEC program approved by the BCUC.

Caribbean Utilities is party to primary and secondary fuel supply contracts and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2016 is 20 million imperial gallons. Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $1,340 million as at December 31, 2015 have been excluded from the Commitments table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 8.

34. CONTINGENCIES

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

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

UNS Energy

Springerville Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") 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 ("New York Action") 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 ("AAA") 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 AAA 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 owner 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 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 at 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, the Company cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the 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.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company 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 (Note 17).

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 is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset (Note 8 *(ix)*).

Central Hudson

Site Investigation and Remediation Program

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 ("DEC"), 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 DEC 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 site investigation and 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 PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return. In the three-year rate order issued by the PSC in June 2015, Central Hudson's authorization to defer all site investigation and remediation costs was reaffirmed and extended through June 2018 (Note 8 *(iv)*).

34. CONTINGENCIES (cont'd)

Central Hudson (cont'd)

Asbestos Litigation

Prior to and after its acquisition by Fortis, various asbestos lawsuits have 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 the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding 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 the consolidated financial statements.

FortisBC Electric

The Government of British Columbia filed a claim in the British Columbia 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 consolidated financial statements.

FHI

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

35. SUBSEQUENT EVENT

On February 9, 2016, Fortis and ITC (NYSE:ITC) entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction (the "Acquisition") 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 Improvements 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 and 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 U.S. Securities and Exchange Commission 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.

36. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period presentation. As a result of the adoption of new accounting policies in 2015 (Note 3), the following changes to the Corporation's comparative financial statements were made:

(i) the reclassification of deferred financing costs of approximately $65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014 (Note 15); and

(ii) the presentation of all deferred income tax assets and liabilities as long term. This change in presentation resulted in the following reclassifications: (i) a decrease in current deferred income taxes assets of $158 million; (ii) a decrease in long-term deferred income tax assets of $62 million; (iii) a decrease in current deferred income tax liabilities of $9 million; and (iv) a decrease in long-term deferred income tax liabilities of $211 million on the consolidated balance sheet as at December 31, 2014 (Note 26). In addition, the Corporation also reclassified the associated regulatory deferred income taxes as long-term, resulting in the following reclassifications: (i) a decrease in current regulatory assets of $18 million; (ii) a decrease in long-term regulatory assets of $92 million; (iii) a decrease in current regulatory liabilities of $19 million; and (iv) a decrease in long-term regulatory liabilities of $91 million on the consolidated balance sheet as at December 31, 2014 (Note 8).

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2015** [1]	2014 [1][2][3]	2013 [1][3]
Revenue	**6,727**	5,401	4,047
Energy supply costs and operating expenses	**4,425**	3,690	2,654
Depreciation and amortization	**873**	688	541
Other income (expenses), net	**187**	(25)	(31)
Finance charges	**553**	547	389
Income tax expense	**223**	66	32
Earnings from continuing operations	**840**	385	400
Earnings from discontinued operations, net of tax	**–**	5	–
Extraordinary gain, net of tax	**–**	–	20
Net earnings	**840**	390	420
Net earnings attributable to non-controlling interests	**35**	11	10
Net earnings attributable to preference equity shareholders	**77**	62	57
Net earnings attributable to common equity shareholders	**728**	317	353
Balance Sheets *(in $ millions)*			
Current assets	**1,857**	1,787	1,296
Goodwill	**4,173**	3,732	2,075
Other long-term assets	**2,638**	2,410	1,925
Utility capital assets, non-utility capital assets and intangible assets	**20,136**	18,304	12,612
Total assets	**28,804**	26,233	17,908
Current liabilities	**2,638**	2,676	2,084
Other long-term liabilities	**5,029**	4,534	3,024
Long-term debt (excluding current portion)	**10,784**	9,911	6,424
Preference shares (classified as debt)	**–**	–	–
Total liabilities	**18,451**	17,121	11,532
Shareholders' equity	**10,353**	9,112	6,376
Cash Flows *(in $ millions)*			
Operating activities	**1,673**	982	899
Investing activities	**(1,368)**	(4,199)	(2,164)
Financing activities, excluding dividends	**(14)**	3,627	1,434
Dividends, excluding dividends on preference shares classified as debt	**(332)**	(266)	(248)
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**9.75**	5.45	8.06
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease and finance obligations (net of cash)	**54.8**	56.4	56.2
Preference shares (classified as debt and equity)	**8.3**	9.1	9.0
Common shareholders' equity	**36.9**	34.5	34.8
Interest Coverage *(x)*			
Debt	**2.7**	1.6	1.9
All fixed charges	**2.7**	1.6	1.9
Total gross capital expenditures *(in $ millions)*	**2,243**	1,725	1,175
Common share data			
Book value per share (year end) *($)*	**28.62**	24.89	22.38
Average common shares outstanding *(in millions)*	**278.6**	225.6	202.5
Basic earnings per common share *($)*	**2.61**	1.41	1.74
Dividends declared per common share *($)*	**1.43**	1.30	1.25
Dividends paid per common share *($)*	**1.40**	1.28	1.24
Dividend payout ratio *(%)*	**53.6**	90.8	71.3
Price earnings ratio *(x)*	**14.3**	27.6	17.5
Share trading summary (TSX)			
High price *($)*	**42.23**	40.83	35.14
Low price *($)*	**34.16**	29.78	29.51
Closing price *($)*	**37.41**	38.96	30.45
Volume *(in thousands)*	**172,038**	174,566	120,470

[1] Financial information for the years 2010 through 2015 prepared under US generally accepted accounting principles ("GAAP"); prior to 2010 prepared under Canadian GAAP.

[2] Certain 2014 comparative figures have been reclassified to comply with current period classifications.

[3] Results were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014 and Central Hudson in 2013.

Historical Financial Summary

2012 (1)	2011 (1)	2010 (1)	2009	2008	2007	2006
3,654	3,738	3,647	3,641	3,907	2,718	1,472
2,390	2,547	2,448	2,577	2,859	1,904	939
470	416	406	364	348	273	178
4	38	13	10	–	8	2
366	363	359	369	363	299	168
61	84	72	49	65	36	32
371	366	375	292	272	214	157
–	–	–	–	–	–	–
–	–	–	–	–	–	–
371	366	375	292	272	214	157
9	9	10	12	13	15	8
47	46	45	18	14	6	2
315	311	320	262	245	193	147
1,093	1,132	1,205	1,124	1,150	1,038	405
1,568	1,565	1,561	1,560	1,575	1,544	661
1,715	1,580	1,309	917	487	424	331
10,574	9,937	9,336	8,538	7,954	7,276	4,049
14,950	14,214	13,411	12,139	11,166	10,282	5,446
1,350	1,305	1,491	1,592	1,697	1,804	558
2,449	2,281	1,977	1,325	763	732	508
5,741	5,685	5,616	5,239	4,848	4,588	2,532
–	–	–	320	320	320	320
9,540	9,271	9,084	8,476	7,628	7,444	3,918
5,410	4,943	4,327	3,663	3,538	2,838	1,528
992	915	742	681	661	373	263
(1,096)	(1,115)	(980)	(1,045)	(852)	(2,033)	(634)
396	386	451	563	387	1,826	456
(225)	(206)	(189)	(176)	(191)	(146)	(77)
8.06	8.79	10.06	8.41	8.70	10.00	11.87
55.3	57.1	60.4	60.2	59.5	64.3	61.1
9.7	8.3	8.7	6.9	7.3	5.2	10.0
35.0	34.6	30.9	32.9	33.2	30.5	28.9
2.0	2.0	2.0	1.9	1.9	1.9	2.2
2.0	2.0	2.0	1.8	1.8	1.7	2.0
1,146	1,171	1,071	1,024	935	803	500
20.84	20.25	18.65	18.61	17.97	16.69	12.19
190.0	181.6	172.9	170.2	157.4	137.6	103.6
1.66	1.71	1.85	1.54	1.56	1.40	1.42
1.21	1.17	1.41	0.78	1.01	0.88	0.70
1.20	1.16	1.12	1.04	1.00	0.82	0.67
72.3	67.8	60.5	67.5	64.1	58.6	47.2
20.6	19.5	18.4	18.6	15.8	20.7	21.0
34.98	35.45	34.54	29.24	29.94	30.00	30.00
31.70	28.24	21.60	21.52	20.70	24.50	20.36
34.22	33.37	33.98	28.68	24.59	28.99	29.77
115,962	126,341	120,855	121,162	132,108	100,920	60,094

Investor Information

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 18, 2016	August 19, 2016
November 18, 2016	February 16, 2017

Dividend Payment Dates

June 1, 2016	September 1, 2016
December 1, 2016	March 1, 2017

Earnings Release Dates

May 3, 2016	July 29, 2016
November 4, 2016	February 16, 2017

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

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare" or "Transfer Agent") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

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Toronto, ON M5J 2Y1
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F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

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

Annual Meeting

Thursday, May 5, 2016
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")(1) and a Consumer Share Purchase Plan ("CSPP")(2) as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

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 Inc. are listed on the Toronto Stock Exchange and trade under the ticker 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.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

Analyst and Investor Inquiries

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E: investorrelations@fortisinc.com

Fortis Inc. Executive

Barry V. Perry
President and Chief Executive Officer

Karl W. Smith
Executive Vice President, Chief Financial Officer

Nora M. Duke
Executive Vice President,
Corporate Services and Chief Human Resource Officer

Earl A. Ludlow
Executive Vice President,
Eastern Canadian and Caribbean Operations

David C. Bennett
Vice President, Chief Legal Officer and Corporate Secretary

Janet A. Craig
Vice President, Investor Relations

Karen J. Gosse
Vice President, Planning and Forecasting

Annette M. Iwasaki
Vice President, Talent Management

James D. Roberts
Vice President, Controller

James D. Spinney
Vice President, Treasurer

Photography:
David Sanders, Tucson, AZ
Christopher Valdez, Poughkeepsie, NY
Oscar Alonzo, San Ignacio, BZ
Doell Photography, Trail, BC
Shawn Talbot, Kelowna, BC
Ned Pratt, St. John's, NL

Design and Production:
Colour, St. John's, NL
colour-nl.ca

Moveable Inc., Toronto, ON

Printer:
The Lowe-Martin Group, Ottawa, ON

Board of Directors

David G. Norris ∗ ✷ ★
Chair, Fortis Inc.
St. John's, Newfoundland and Labrador

Tracey C. Ball ∗
Corporate Director
Edmonton, Alberta

Pierre J. Blouin ✷
Corporate Director
Ile Bizard, Quebec

Peter E. Case ∗ ★
Corporate Director
Kingston, Ontario

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Douglas J. Haughey ∗ ✷
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Calgary, Alberta

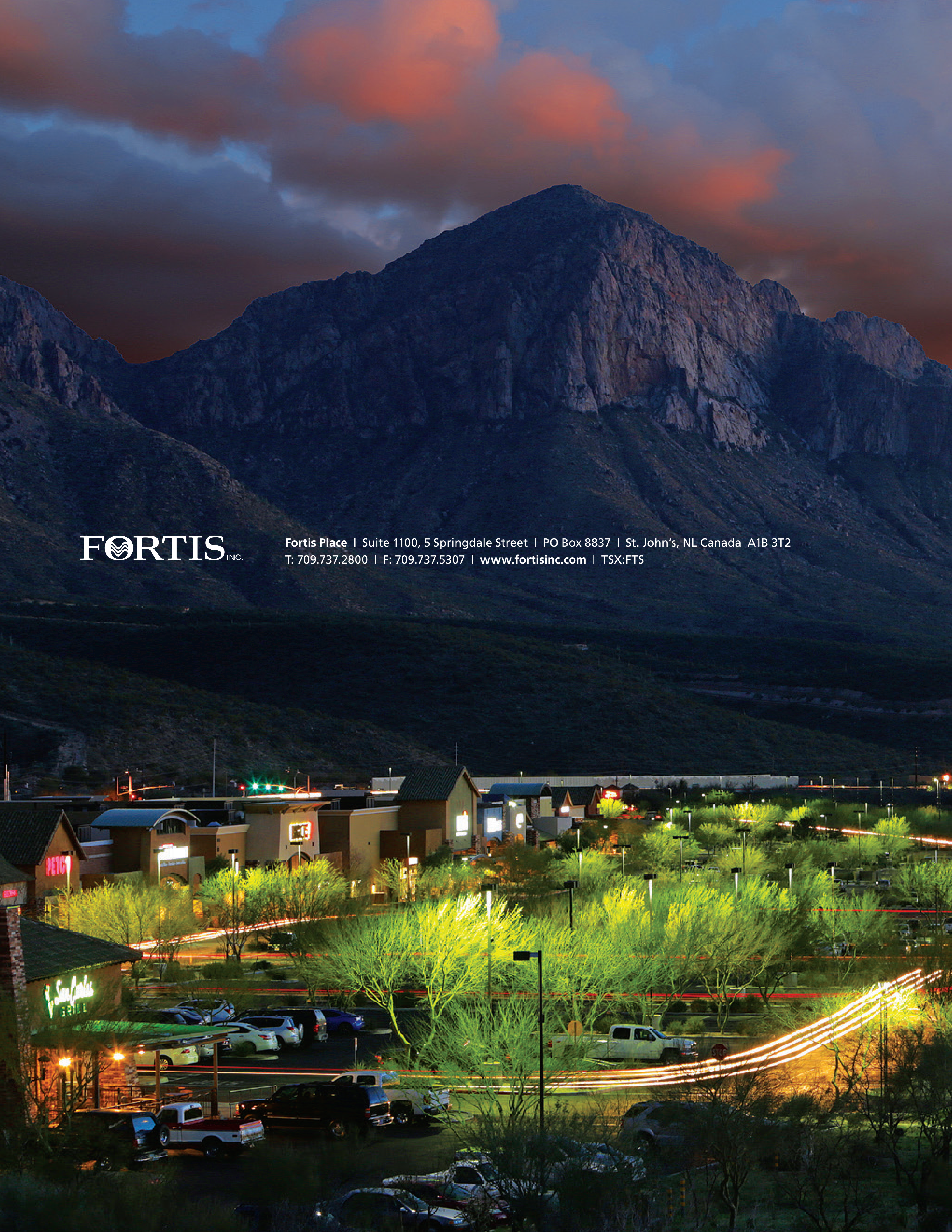
Harry McWatters ★
President, Vintage Consulting Group Inc.
Summerland, British Columbia

Ronald D. Munkley ✷ ★
Corporate Director
Mississauga, Ontario

Barry V. Perry
President and CEO, Fortis Inc.
St. John's, Newfoundland and Labrador

∗ Audit Committee
✷ Human Resources Committee
★ Governance and Nominating Committee

For Board of Directors' biographies, please visit www.fortisinc.com.



FORTIS INC.

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Fortis Inc. (TSX: FTS)

Balance Sheet (As-Reported)

SNL Institution Key: 4082871

Periods: 2015 FY, 2014 FY, 2013 FY

	2015 FY	2014 FY	2013 FY
As Of Date	12/31/2015	12/31/2014	12/31/2013
Source Document	12/31/2015 Financial Supplement	12/31/2015 Financial Supplement	12/31/2014 Financial Supplement
Spot Exchange Rate	0.719424	0.864379	0.941265
Average Exchange Rate	NA	NA	NA
Currency Code	USD	USD	USD
(in millions)			
ASSETS			
Current assets			
Cash and cash equivalents	174	199	68
Accounts receivable and other current assets	694	778	689
Prepaid expenses	49	51	42
Inventories	242	277	135
Regulatory assets	177	239	141
Assets held for sale	NA	NA	105
Deferred income taxes	NA	NA	40
Total	1,336	1,545	1,220
Other assets	253	235	232
Regulatory assets	1,645	1,848	1,574
Deferred income taxes	NA	NA	7
Utility capital assets	14,097	14,849	10,936
Non-utility capital assets	0	574	611
Intangible assets	389	398	325
Goodwill	3,002	3,226	1,953
Total	20,722	22,675	16,856
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Short-term borrowings	368	285	151
Accounts payable and other current liabilities	1,021	1,245	901
Regulatory liabilities	214	150	132
Current installments of long-term debt	276	454	734
Current installments of capital lease and finance obligations	19	180	7
Liabilities associated with assets held for sale	NA	NA	30
Deferred income taxes	NA	NA	8
Total	1,898	2,313	1,962
Other liabilities	829	986	590
Regulatory liabilities	964	1,099	849
Deferred income taxes	NA	NA	1,015
Deferred income taxes	1,475	1,405	NA
Long-term debt	7,758	8,567	6,047
Capital lease and finance obligations	350	428	393
Total liabilities	13,274	14,799	10,855
Shareholders' equity			
Common shares	4,221	4,898	3,561
Preference shares	1,309	1,573	1,157
Additional paid-in capital	10	13	16
Accumulated other comprehensive income	569	112	(68)
Retained earnings	999	916	983
Total Shareholders' equity	7,108	7,512	5,649
Non-controlling interests	340	364	353
Total	7,448	7,876	6,002
Total	20,722	22,675	16,856

Fortis Inc. (TSX: FTS)
Income Statement (As-Reported)
SNL Institution Key: 4082871

Periods: 2015 FY, 2014 FY, 2013 FY

	2015 FY	2014 FY	2013 FY
As Of Date	12/31/2015	12/31/2014	12/31/2013
Source Document	12/31/2015 Financial Supplement	12/31/2015 Financial Supplement	12/31/2014 Financial Supplement
Spot Exchange Rate	NA	NA	NA
Average Exchange Rate	0.78314	0.905757	0.970901
Currency Code	USD	USD	USD
(in millions)			
Revenue	5,268	4,892	3,929
Expenses			
Energy supply costs	2,006	1,990	1,570
Operating	1,460	1,352	1,007
Depreciation and amortization	684	623	525
Total	4,149	3,965	3,102
Operating income	1,119	927	827
Other income (expenses), net	146	(23)	(30)
Finance charges	433	495	378
Earnings before income taxes and discontinued operations	832	408	419
Income tax expense	175	60	31
Earnings from continuing operations	658	349	388
Earnings from discontinued operations, net of tax	0	5	0
Earnings before extraordinary item	NA	NA	388
Extraordinary gain, net of tax	NA	NA	19
Net earnings	658	353	408
Net earnings attributable to			
Non-controlling interests	27	10	10
Preference equity shareholders	60	56	55
Common equity shareholders	570	287	343
Total	658	353	408
Earnings per common share from continuing operations			
Basic (actual)	2.04	1.26	1.59
Diluted (actual)	2.03	1.25	1.58
Earnings per common share			
Basic (actual)	2.04	1.28	1.69
Diluted (actual)	2.03	1.27	1.68
Consolidated Statements of Comprehensive Income			
Net earnings	658	353	408
Other comprehensive income (loss)			
Unrealized foreign currency translation gains, net of hedging	517	185	16
Reclassification of unrealized foreign currency translation los	NA	NA	NA
Reclassification to earnings of foreign currency translation lo	2	0	NA
Net change in fair value of cash flow hedges, net of tax	1	1	0
Reclassification to earnings of net losses on derivative instru	0	1	1
Unrealized loss on available-for-sale investment, net of tax	(2)	0	NA
Unrealized employee future benefits gains (losses), net of ta	1	(5)	7
Total	518	182	23
Comprehensive income	1,176	535	431
Comprehensive income attributable to			
Non-controlling interests	27	10	10
Preference equity shareholders	60	56	55
Common equity shareholders	1,089	469	366
Total	1,176	535	431

Data shown on this page is extracted directly from the company's documents. SNL makes every effort to line up fields, captions and headers that represent the same data over time, despite variations in how the company may report these items in different documents. In certain instances the variation in the company's presentation over time may be too significant, potentially resulting in repeating and/or disordered items. Despite possible issues with the presentation, SNL, as always, stands by its commitment to the quality of the data.

Fortis Inc. (TSX: FTS)
Cash Flow Statement
SNL Institution Key: 4082871

Native Currency: CAD
Current Currency: USD

	2015 FY	2014 FY	2013 FY
Period Ended	12/31/2015	12/31/2014	12/31/2013
Period Restated?	No	No	No
Restatement Date	NA	NA	NA
Spot Exchange Rate	0.719424	0.864379	0.941265
Average Exchange Rate	0.783140	0.905757	0.970901
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP
Operating Activity ($000)			
Net Income	657,838	353,245	407,778
Cash Flow: Depreciation and Amortization	683,681	623,161	525,257
Cash Flow: Amortization of Nuclear Fuel	0	0	0
Cash Flow: Deferred Taxes & Investment Tax Credits	128,435	20,832	(5,825)
Cash Flow: Operating Changes in AFUDC	(18,012)	(9,963)	(7,767)
Cash Flow: Change in Working Capital	32,109	(112,314)	(43,691)
Cash Flow: Other Operating Changes in Cash	(173,857)	14,492	(2,913)
Cash Flow from Operating Activities	1,310,193	889,453	872,840
Adjusted Cash Flow from Operations ($000)			
Net Income	657,838	353,245	407,778
Cash Flow: Depreciation and Amortization	683,681	623,161	525,257
Cash Flow: Deferred Taxes & Investment Tax Credits	128,435	20,832	(5,825)
Cash Flow: Other Operating Changes in Cash	(173,857)	14,492	(2,913)
Cash Flow: Amortization of Nuclear Fuel	0	0	0
Adjusted Cash Flow from Operations	1,296,097	1,011,730	924,298
Investing Activity ($000)			
Cash Flow: Capital Expenditures	(1,668,871)	(1,499,933)	(1,101,972)
Cash Flow from Asset Purchases	(142,531)	(2,460,941)	(1,063,136)
Cash Flow from Asset Sales	722,055	98,727	19,418
Cash Flow from Asset Sales & Purchases	579,524	(2,362,213)	(1,043,718)
Net Investment in Nuclear Decommissioning Trust	0	0	0
Cash Flow: Investing Changes in AFUDC	NA	NA	NA
Cash Flow: Other Investing Changes in Cash	18,012	58,874	44,661
Cash Flow from Investing Activities	(1,071,335)	(3,803,272)	(2,101,029)
Financing Activity ($000)			
Net Proceeds from Issuance of Short-term Debt	NA	NA	NA
Cash Flow: Short-term Debt Repayments	NA	NA	NA
Net Change in Short-term Debt	115,905	151,261	(5,825)
Net Proceeds from Issuance of Long-term Debt	NA	NA	NA
Cash Flow: Long-term Debt Repayments	NA	NA	NA
Net Change in Long-term Debt	(173,857)	2,522,532	644,678
Preferred Equity Net Proceeds	0	530,773	234,958
Cash Flow: Preferred Share Repurchases	0	0	(121,363)
Cash Flow: Net Change in Preferred Issues	0	530,773	113,595
Common Equity Net Proceeds	31,326	46,194	578,657
Cash Flow: Common Share Repurchases	0	0	0
Cash Flow: Net Change in Common Issues	31,326	46,194	578,657
Cash Flow: Common Dividends Paid	(181,688)	(175,717)	(175,733)
Preferred Dividends Paid	(60,302)	(56,157)	(54,370)
Dividends Paid	(241,990)	(231,874)	(230,103)

Cash Flow: Other Financing Changes in Cash	(2,349)	25,361	50,487
Cash Flow from Financing Activities	(270,966)	3,044,248	1,151,488
Other Cash Flow ($000)			
Other Cash Flow	41,506	12,681	(2,913)
Net Increase in Cash and Cash Equivalents	9,398	143,110	(79,614)
Mark-to-Market Adjustment	NA	NA	NA
Interest Paid	439,341	487,297	399,040
Income Taxes Paid	85,362	75,178	55,341
Dividends Paid to Parent Company	0	0	0
Projected Capital Expenditures ($000)			
Planned Capital Expenditures for This Fiscal Year	1,367,626	1,860,143	1,346,009
Planned Capital Expenditures for Next Fiscal Year	1,366,906	1,469,444	1,193,053
Planned Capital Expenditures Second Fiscal Year	1,366,906	1,555,882	1,193,053

Note: SNL uses a variety of sources to retrieve financial information for each company we cover. For Energy companies, SNL mines data from documents filed by the company, surveys, and other sources of public information.

CH ENERGY GROUP, INC.
&
CENTRAL HUDSON GAS & ELECTRIC CORP.

ANNUAL FINANCIAL REPORT

for the period ended

DECEMBER 31, 2015

Report of Independent Auditors

The Board of Directors of CH Energy Group, Inc.

We have audited the accompanying consolidated financial statements of CH Energy Group, Inc. and subsidiaries, which comprise the consolidated balance sheets as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, equity and cash flows for the years ended December 31, 2015, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in conformity with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of CH Energy Group, Inc. and subsidiaries at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Canada
February 17, 2016

Report of Independent Auditors

The Board of Directors Central Hudson Gas & Electric Corporation

We have audited the accompanying balance sheet of Central Hudson Gas & Electric Corporation as of December 31, 2015 and 2014, and the related statements of income, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Central Hudson Gas & Electric Corporation at December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Central Hudson Gas & Electric Corporation's internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 17, 2016 expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Canada
February 17, 2016

Report of Independent Auditors

The Board of Directors of Central Hudson Gas & Electric Corporation

We have audited Central Hudson Gas & Electric Corporation's internal control over financial reporting as at December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Central Hudson Gas & Electric Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Central Hudson Report of Management on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Central Hudson Gas & Electric Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the balance sheet of Central Hudson Gas & Electric Corporation as of December 31, 2015 and 2014, and the related statements of income, comprehensive income, equity and cash flows for each of the three years ended December 31, 2015 and our report dated February 17, 2016 expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Canada
February 17, 2016

REPORT OF MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING – CENTRAL HUDSON

The management of Central Hudson Gas & Electric Corporation ("management") is responsible for establishing and maintaining adequate internal control over financial reporting for Central Hudson Gas & Electric Corporation (the "Corporation") as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Corporation;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and that receipts and expenditures of the Corporation are being made only in accordance with authorization of management and directors of the Corporation; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the consolidated financial statements.

Internal control over financial reporting includes the controls themselves, monitoring (including internal auditing practices) and actions taken to correct deficiencies as identified.

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

Management assessed the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2015. Management based this assessment on criteria for effective internal control over financial reporting described in "*Internal Control - Integrated Framework*" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management determined that, as of December 31, 2015, the Corporation maintained effective internal control over financial reporting.

The effectiveness of the Corporation's internal control over financial reporting as of December 31, 2015, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which appears herein.

/s/ James P. Laurito	/s/ Christopher M. Capone
James P. Laurito Chief Executive Officer	Christopher M. Capone Executive Vice President and Chief Financial Officer

February 17, 2016

YEAR ENDED DECEMBER 31, 2015

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CH ENERGY GROUP CONSOLIDATED STATEMENT OF INCOME

(In Thousands)

	Year Ended December 31, 2015	2014	2013
Operating Revenues			
Electric	$ 544,296	$ 579,757	$ 532,539
Natural gas	146,562	163,005	135,904
Total Operating Revenues	690,858	742,762	668,443
Operating Expenses			
Operation:			
Purchased electricity and fuel used in electric generation	193,920	232,990	185,736
Purchased natural gas	53,890	78,765	51,342
Other expenses of operation - regulated activities	240,302	250,046	241,366
Other expenses of operation - non-regulated	75	7,129	992
Merger related costs	-	86	16,292
Depreciation and amortization	44,074	43,859	40,218
Regulatory Debits	-	-	40,000
Taxes, other than income tax	58,065	55,497	53,499
Total Operating Expenses	590,326	668,372	629,445
Operating Income	100,532	74,390	38,998
Other Income and Deductions			
Income from unconsolidated affiliates	131	586	505
Interest on regulatory assets and other interest income	3,585	4,395	5,884
Regulatory adjustments for interest costs	653	1,259	1,280
Other - net	1,378	(700)	(600)
Total Other Income	5,747	5,540	7,069
Interest Charges			
Interest on long-term debt	23,549	23,528	25,443
Interest on regulatory liabilities and other interest	7,862	9,575	8,316
Total Interest Charges	31,411	33,103	33,759
Income before income taxes	74,868	46,827	12,308
Income Tax Expense	31,128	20,196	7,574
Net Income from Continuing Operations	43,740	26,631	4,734
Discontinued Operations			
Income from discontinued operations before tax	-	6,908	7,540
Gain from sale of discontinued operations	-	8,036	-
Income tax expense from discontinued operations	-	7,255	3,092
Net Income from Discontinued Operations	-	7,689	4,448
Dividends declared on Preferred Stock of subsidiary	-	-	92
Preferred Stock Redemption Premium	-	-	764
Net Income Attributable to CH Energy Group	43,740	34,320	8,326
Dividends declared on Common Stock	22,000	75,000	18,310
Change in Retained Earnings	$ 21,740	$ (40,680)	$ (9,984)

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(In Thousands)

	Year Ended December 31,		
	2015	2014	2013
Net Income	$ 43,740	$ 34,320	$ 9,182
Other Comprehensive Income:			
Net unrealized gain/(losses) on investments held by equity method investees - net of tax of $210, ($3) and ($83), respectively	(316)	6	124
Other comprehensive income (loss)	(316)	6	124
Comprehensive income	43,424	34,326	9,306
Comprehensive income attributable to non-controlling interest	-	-	856
Comprehensive income attributable to CH Energy Group	$ 43,424	$ 34,326	$ 8,450

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP CONSOLIDATED STATEMENT OF CASH FLOWS

(In Thousands)

	Year Ended December 31, 2015	2014	2013
Operating Activities:			
Net income	$ 43,740	$ 34,320	$ 9,182
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	40,830	40,702	39,938
Amortization	3,244	3,157	5,274
Deferred income taxes - net	23,065	15,741	9,655
Bad debt expense	7,598	6,645	3,829
Undistributed equity in earnings of unconsolidated affiliates	(131)	171	(505)
Pension expense	18,138	21,152	20,601
Other post-employment benefits ("OPEB") expense	2,394	6,803	6,803
Positive Benefit Adjustment expense	-	-	40,000
Regulatory liability - rate moderation	(6,173)	-	-
Revenue decoupling mechanism recorded	10,468	3,245	2,774
Regulatory asset amortization	27	4,554	4,554
Gain on sale of assets	-	(8,073)	(70)
Changes in operating assets and liabilities - net:			
Accounts receivable, unbilled revenues and other receivables	2,909	(25,700)	(7,677)
Fuel, materials and supplies	(1,237)	1,209	513
Special deposits and prepayments	(823)	(4,357)	(2,739)
Income and other taxes	(22,139)	(16,208)	106
Accounts payable	(8,978)	17,201	(7,534)
Accrued interest	(170)	(221)	(37)
Customer advances	3,810	(3,396)	(6,229)
Pension plan contribution	(22,387)	(16,986)	(26,641)
OPEB contribution	(1,536)	(2,238)	(2,894)
Revenue decoupling mechanism collected/(refunded)	(1,258)	(5,105)	1,956
Regulatory asset - storm deferral	(51)	(5,108)	3,450
Regulatory asset - manufactured gas plant ("MGP") site remediation	2,873	4,202	(1,453)
Regulatory asset - Temporary State Assessment	(109)	1,185	2,220
Deferred natural gas and electric costs	20,095	(8,389)	(9,726)
Other - net	(9,918)	23,065	13,170
Net cash provided by operating activities	104,281	87,571	98,520
Investing Activities:			
Proceeds from sale of assets	-	95,281	103
Additions to utility and other property and plant	(140,648)	(113,321)	(110,972)
Other - net	(4,311)	1,861	(5,312)
Net cash used in investing activities	(144,959)	(16,179)	(116,181)
Financing Activities:			
Redemption of long-term debt	(1,230)	(21,651)	(47,777)
Proceeds from issuance of long-term debt	20,000	30,000	46,700
Borrowings/(redemption) of short-term debt - net	25,000	-	(19,500)
Proceeds from issuance of stock	-	-	65,000
Additional paid in capital	10,000	-	
Dividends paid on Common Stock	(22,000)	(75,000)	(26,611)
Redemption of Preferred Stock	-	-	(9,625)
Dividends paid on Preferred Stock of subsidiary	-	-	(92)
Other - net	(157)	(207)	(372)
Net cash provided by (used in) financing activities	31,613	(66,858)	7,723
Net Change in Cash and Cash Equivalents	(9,065)	4,534	(9,938)
Cash and Cash Equivalents at Beginning of Period	22,647	18,113	30,508
Cash and Cash Equivalents at End of Period	$ 13,582	$ 22,647	$ 20,570
Supplemental Disclosure of Cash Flow Information:			
Interest paid	$ 23,529	$ 24,147	$ 26,048
Federal and state income taxes paid	$ 41,712	$ 17,000	$ 2,158
Additions to plant included in liabilities	$ 12,010	$ 7,495	$ 5,901

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP CONSOLIDATED BALANCE SHEET

(In Thousands)

	December 31, 2015	December 31, 2014
ASSETS		
Utility Plant (Note 2)		
Electric	$ 1,230,663	$ 1,160,643
Natural gas	417,455	380,966
Common	201,193	184,804
Gross Utility Plant	1,849,311	1,726,413
Less: Accumulated depreciation	478,384	458,155
Net	1,370,927	1,268,258
Construction work in progress	51,517	57,543
Net Utility Plant	1,422,444	1,325,801
Non-utility property & plant	524	524
Net Non-Utility Property & Plant	524	524
Current Assets		
Cash and cash equivalents	13,582	22,647
Accounts receivable from customers - net of allowance for doubtful accounts of $5.6 million and $4.8 million, respectively.	55,340	68,568
Accounts receivable - affiliates	195	-
Accrued unbilled utility revenues	28,216	16,866
Other receivables	7,873	5,208
Fuel, materials and supplies (Note 1)	18,783	17,546
Regulatory assets (Note 3)	30,788	55,891
Income tax receivable	38,139	10,694
Special deposits and prepayments	26,296	25,473
Total Current Assets	219,212	222,893
Deferred Charges and Other Assets		
Regulatory assets - pension plan (Note 3)	94,488	94,426
Regulatory assets - other (Note 3)	140,166	195,684
Fair value of derivative instruments (Note 14)	2,218	570
Investments in unconsolidated affiliates (Note 5)	1,417	1,726
Other investments (Note 15)	33,575	27,666
Other	3,514	3,001
Total Deferred Charges and Other Assets	275,378	323,073
Total Assets	$ 1,917,558	$ 1,872,291

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP CONSOLIDATED BALANCE SHEET (CONT'D)
(In Thousands, except share amounts)

	December 31, 2015	December 31, 2014
CAPITALIZATION AND LIABILITIES		
Capitalization (Note 8)		
CH Energy Group Common Shareholders' Equity		
Common Stock (30,000,000 shares authorized: $0.01 par value; 15,961,400 shares issued and outstanding)	$ 160	$ 160
Paid-in capital	335,906	325,906
Retained earnings	219,179	197,439
Accumulated other comprehensive income	194	510
Total Equity	555,439	524,015
Long-term debt (Note 9)		
Principal amount	534,730	524,045
Unamortized debt issuance costs	(3,894)	(4,096)
Long-term debt less unamortized debt issuance costs	530,836	519,949
Total Capitalization	1,086,275	1,043,964
Current Liabilities		
Current maturities of long-term debt (Note 9)	9,315	1,230
Notes payable (Note 7)	25,000	-
Accounts payable	39,305	44,312
Accounts payable - affiliates	-	9
Accrued interest	5,503	5,673
Accrued vacation and payroll	7,030	9,513
Customer advances	17,977	14,167
Customer deposits	8,366	6,948
Regulatory liabilities (Note 3)	42,429	11,259
Fair value of derivative instruments (Note 14)	10,142	7,727
Accrued environmental remediation costs (Note 12)	22,998	13,425
Other	8,806	17,966
Total Current Liabilities	196,871	132,229
Deferred Credits and Other Liabilities		
Regulatory liabilities - OPEB (Note 3)	25,663	47,339
Regulatory liabilities - other (Note 3)	132,988	161,272
Operating reserves	3,703	4,118
Fair value of derivative instruments (Note 14)	1,476	-
Accrued environmental remediation costs (Note 12)	69,121	93,700
Accrued OPEB costs (Note 10)	18,995	24,836
Accrued pension costs (Note 10)	59,570	68,507
Tax reserve (Note 4)	3,520	2,693
Other	19,910	19,651
Total Deferred Credits and Other Liabilities	334,946	422,116
Accumulated Deferred Income Tax (Note 4)	299,466	273,982
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 1,917,558	$ 1,872,291

The Notes to Financial Statements are an integral part hereof.

CH ENERGY GROUP CONSOLIDATED STATEMENT OF EQUITY

(In Thousands, except share amounts)

	CH Energy Group Common Shareholders									
	Common Stock		Treasury Stock							
	Shares Issued	Amount	Shares Repurchased	Amount	Paid-In Capital	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Income / (Loss)	Non-controlling Interest	Total Equity
Balance at December 31, 2012	16,862,087	$ 1,686	(1,907,203)	$ (90,141)	$ 349,428	$ (166)	$ 248,103	$ 380	$ -	$ 509,290
Comprehensive Income:										
Net income							9,182			9,182
Preferred Stock Redemption					(28)	166	(764)			(626)
Dividends declared on Preferred Stock of subsidiary							(92)			(92)
Change in fair value:										
Investments								124		124
Dividends declared on common stock							(18,310)			(18,310)
Common Stock Cancelled	(16,862,087)	(1,686)			(349,828)					(351,514)
Common Stock Issued	15,961,400	160			325,906					326,066
Treasury shares activity - net			1,907,203	90,141	428					90,569
Balance at December 31, 2013	15,961,400	$ 160	-	$ -	$ 325,906	$ -	$ 238,119	$ 504	$ -	$ 564,689
Comprehensive Income:										
Net income							34,320			34,320
Change in fair value:										
Investments								6		6
Dividends declared on common stock							(75,000)			(75,000)
Balance at December 31, 2014	15,961,400	$ 160	-	$ -	$ 325,906	$ -	$ 197,439	$ 510	$ -	$ 524,015
Comprehensive Income:										
Net income							43,740			43,740
Change in fair value:										
Capital Contributions					10,000					10,000
Investments								(316)		(316)
Dividends declared on common stock							(22,000)			(22,000)
Balance at December 31, 2015	15,961,400	$ 160	-	$ -	$ 335,906	$ -	$ 219,179	$ 194	$ -	$ 555,439

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON STATEMENT OF INCOME

(In Thousands)

	Year Ended December 31, 2015	2014	2013
Operating Revenues			
Electric	$ 544,296	$ 579,757	$ 532,539
Natural gas	146,562	163,005	135,904
Total Operating Revenues	690,858	742,762	668,443
Operating Expenses			
Operation:			
Purchased electricity and fuel used in electric generation	193,920	232,990	185,736
Purchased natural gas	53,890	78,765	51,342
Other expenses of operation	240,302	250,046	241,366
Depreciation and amortization	44,074	43,859	40,218
Regulatory Debits	-	-	40,000
Taxes, other than income tax	57,903	54,726	53,334
Total Operating Expenses	590,089	660,386	611,996
Operating Income	100,769	82,376	56,447
Other Income and Deductions			
Interest on regulatory assets and other interest income	3,551	4,355	5,838
Regulatory adjustments for interest costs	653	1,259	1,280
Other - net	1,869	(214)	105
Total Other Income	6,073	5,400	7,223
Interest Charges			
Interest on long-term debt	22,259	22,031	23,570
Interest on regulatory liabilities and other interest	7,849	9,540	8,153
Total Interest Charges	30,108	31,571	31,723
Income Before Income Taxes	76,734	56,205	31,947
Income Tax Expense	31,146	22,361	11,648
Net Income	45,588	33,844	20,299
Preferred Stock Redemption Premium	-	-	764
Dividends Declared on Cumulative Preferred Stock	-	-	92
Income Available for Common Stock	$ 45,588	$ 33,844	$ 19,443

CENTRAL HUDSON STATEMENT OF COMPREHENSIVE INCOME

(In Thousands)

	Year Ended December 31, 2015	2014	2013
Net Income	$ 45,588	$ 33,844	$ 20,299
Other Comprehensive Income	-	-	-
Comprehensive Income	$ 45,588	$ 33,844	$ 20,299

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON STATEMENT OF CASH FLOWS

(In Thousands)

	Year Ended December 31, 2015	2014	2013
Operating Activities:			
Net income	$ 45,588	$ 33,844	$ 20,299
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	40,830	40,702	37,589
Amortization	3,244	3,157	2,629
Deferred income taxes - net	22,777	10,976	8,812
Bad debt expense	7,598	6,645	3,484
Pension expense	18,138	20,597	20,601
OPEB expense	2,394	6,803	6,803
Positive Benefit Adjustment expense	-	-	40,000
Regulatory liability - rate moderation	(6,173)	-	-
Revenue decoupling mechanism recorded	10,468	3,245	2,774
Regulatory asset amortization	27	4,554	4,554
Changes in operating assets and liabilities - net:			
Accounts receivable, unbilled revenues and other receivables	1,923	(9,162)	(8,095)
Fuel, materials and supplies	(1,237)	1,086	632
Special deposits and prepayments	(825)	(4,958)	(1,988)
Income and other taxes	(22,528)	(8,289)	(7,522)
Accounts payable	(8,930)	12,396	(9,556)
Accrued interest	(167)	(132)	(33)
Customer advances	3,810	(834)	(3,083)
Pension plan contribution	(22,064)	(16,986)	(26,641)
OPEB contribution	(1,536)	(2,238)	(2,894)
Revenue decoupling mechanism collected/(refunded)	(1,258)	(5,105)	1,956
Regulatory asset - storm deferral	(51)	(5,108)	3,450
Regulatory asset - MGP site remediation	2,873	4,202	(1,453)
Regulatory asset - Temporary State Assessment	(109)	1,185	2,220
Deferred natural gas and electric costs	20,095	(8,389)	(9,726)
Other - net	(4,688)	16,427	12,564
Net cash provided by operating activities	110,199	104,618	97,376
Investing Activities:			
Additions to utility plant	(140,648)	(113,190)	(108,817)
Other - net	(4,238)	1,703	(6,370)
Net cash used in investing activities	(144,886)	(111,487)	(115,187)
Financing Activities:			
Redemption of long-term debt	-	(14,000)	(46,700)
Proceeds from issuance of long-term debt	20,000	30,000	46,700
Proceeds from issuance of notes payable	27,000	-	-
Redemption of Preferred Stock	-	-	(9,653)
Dividends paid to parent - CH Energy Group	(24,524)	(5,000)	(22,000)
Dividends paid on cumulative Preferred Stock	-	-	(92)
Other - net	(157)	(207)	(417)
Net cash provided by/(used in) financing activities	22,319	10,793	(32,162)
Net Change in Cash and Cash Equivalents	(12,368)	3,924	(49,973)
Cash and Cash Equivalents - Beginning of Period	18,303	14,379	24,352
Cash and Cash Equivalents - End of Period	$ 5,935	$ 18,303	$ (25,621)
Supplemental Disclosure of Cash Flow Information:			
Interest paid	$ 22,235	$ 22,560	$ 24,024
Federal and state income taxes paid	$ 44,798	$ 20,003	$ 10,370
Additions to plant included in liabilities	$ 12,010	$ 7,495	$ -

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON BALANCE SHEET

(In Thousands)

	December 31, 2015	December 31, 2014
ASSETS		
Utility Plant (Note 2)		
Electric	$ 1,230,663	$ 1,160,643
Natural gas	417,455	380,966
Common	201,193	184,804
Gross Utility Plant	1,849,311	1,726,413
Less: Accumulated depreciation	478,384	458,155
Net	1,370,927	1,268,258
Construction work in progress	51,517	57,543
Net Utility Plant	1,422,444	1,325,801
Non-Utility Property and Plant	524	524
Net Non-Utility Property and Plant	524	524
Current Assets		
Cash and cash equivalents	5,935	18,303
Accounts receivable from customers - net of allowance for doubtful accounts of $5.6 million and $4.8 million, respectively.	55,340	68,568
Accrued unbilled utility revenues	28,216	16,866
Other receivables	8,047	4,200
Fuel, materials and supplies - at average cost (Note 1)	18,783	17,546
Regulatory assets (Note 3)	30,788	55,891
Income tax receivable	35,196	12,668
Special deposits and prepayments	26,243	25,418
Total Current Assets	208,548	219,460
Deferred Charges and Other Assets		
Regulatory assets - pension plan (Note 3)	94,488	94,426
Regulatory assets - other (Note 3)	140,166	195,684
Fair value of derivative instruments (Note 14)	2,218	570
Other investments (Note 15)	32,779	26,856
Other	2,865	2,387
Total Deferred Charges and Other Assets	272,516	319,923
Total Assets	$ 1,904,032	$ 1,865,708

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON BALANCE SHEET (CONT'D)

(In Thousands, except share amounts)

	December 31, 2015	December 31, 2014
CAPITALIZATION AND LIABILITIES		
Capitalization (Note 8)		
Common Stock (30,000,000 shares authorized: $5 par value; 16,862,087 shares issued and outstanding)	$ 84,311	$ 84,311
Paid-in capital	239,952	239,952
Retained earnings	237,520	216,456
Capital stock expense	(4,633)	(4,633)
Total Equity	557,150	536,086
Long-term debt (Note 9)		
Principal amount	517,950	505,950
Unamortized debt issuance costs	(3,894)	(4,096)
Long-term debt less unamortized debt issuance costs	514,056	501,854
Total Capitalization	1,071,206	1,037,940
Current Liabilities		
Current maturities of long-term debt (Note 9)	8,000	-
Notes payable (Note 7)	27,000	-
Accounts payable	39,478	44,446
Accrued interest	5,451	5,618
Accrued vacation and payroll	7,025	6,400
Customer advances	17,977	14,167
Customer deposits	8,366	6,948
Regulatory liabilities (Note 3)	42,429	11,259
Fair value of derivative instruments (Note 14)	10,142	7,727
Accrued environmental remediation costs (Note 12)	22,998	13,345
Other	8,644	15,992
Total Current Liabilities	197,510	125,902
Deferred Credits and Other Liabilities		
Regulatory liabilities - OPEB (Note 3)	25,663	47,339
Regulatory liabilities - other (Note 3)	132,988	161,272
Operating reserves	3,703	4,118
Fair value of derivative instruments (Note 14)	1,476	-
Accrued environmental remediation costs (Note 12)	69,121	93,598
Accrued OPEB costs (Note 10)	18,995	24,836
Accrued pension costs (Note 10)	59,337	67,952
Tax reserve (Note 4)	3,520	2,693
Other	18,225	17,870
Total Deferred Credits and Other Liabilities	333,028	419,678
Accumulated Deferred Income Tax (Note 4)	302,288	282,188
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 1,904,032	$ 1,865,708

The Notes to Financial Statements are an integral part hereof.

CENTRAL HUDSON STATEMENT OF EQUITY
(In Thousands, except share amounts)

	Central Hudson Common Shareholders								
	Common Stock		Treasury Stock						
	Shares Issued	Amount	Shares Repurchased	Amount	Paid-In Capital	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Income / (Loss)	Total Equity
Balance at December 31, 2012	16,862,087	$ 84,311	-	$ -	$ 199,980	$ (4,799)	$ 190,169	$ -	$ 469,661
Net income							20,299		20,299
Preferred Stock Redemption					(28)	166	(764)		(626)
Dividends declared									
On cumulative Preferred Stock							(92)		(92)
On Common Stock to parent - CH Energy Group							(22,000)		(22,000)
Additional Paid-in Capital					40,000		-		40,000
Balance at December 31, 2013	16,862,087	$ 84,311	-	$ -	$ 239,952	$ (4,633)	$ 187,612	$ -	$ 507,242
Net income							33,844		33,844
Dividends declared									
On Common Stock to parent - CH Energy Group							(5,000)		(5,000)
Balance at December 31, 2014	16,862,087	$ 84,311	-	$ -	$ 239,952	$ (4,633)	$ 216,456	$ -	$ 536,086
Net income							45,588		45,588
Dividends declared									
On Common Stock to parent - CH Energy Group							(24,524)		(24,524)
Balance at December 31, 2015	16,862,087	$ 84,311	-	$ -	$ 239,952	$ (4,633)	$ 237,520	$ -	$ 557,150

The Notes to Financial Statements are an integral part hereof.

NOTES TO FINANCIAL STATEMENTS

NOTE 1 – Summary of Significant Accounting Policies

Corporate Structure

CH Energy Group is the holding company parent corporation of three principal, wholly owned subsidiaries, Central Hudson Gas & Electric Corporation ("Central Hudson"), Central Hudson Electric Transmission LLC ("CHET") and Central Hudson Enterprises Corporation ("CHEC"). CH Energy Group's common stock is indirectly owned by Fortis Inc. ("Fortis"), which is the largest investor-owned gas and electric distribution utility in Canada. Central Hudson is a regulated electric and natural gas subsidiary. CHET was formed to engage in Federal Energy Regulatory Commission ("FERC") transmission projects and has 6.1% ownership in New York Transco LLC ("Transco"). CHEC, the parent company of CH Energy Group's non-regulated businesses and investments, completed the sale of its wholly owned operating subsidiary Griffith Energy Services, Inc. to Star Gas Partners, L.P. on March 4, 2014. Therefore, operating results of Griffith are reported as Discontinued Operations for the year ended December 31, 2014 in the Consolidated CH Energy Group Statement of Income. See Note 5 – "Acquisitions, Investments and Divestitures" for further information. CHEC also has ownership interests in certain subsidiaries that are less than 100% owned.

Basis of Presentation

This Annual Report is a combined report of CH Energy Group and Central Hudson. The Notes to the Consolidated Financial Statements apply to both CH Energy Group and Central Hudson. CH Energy Group's Consolidated Financial Statements include the accounts of CH Energy Group and its wholly owned subsidiaries, which include Central Hudson, CHET and CHEC. Inter-company balances and transactions have been eliminated in consolidation.

CHEC's investments in limited partnerships ("Partnerships") and limited liability companies are accounted for under the equity method. CHEC's proportionate share of the change in fair value of available-for-sale securities held by the Partnerships is recorded in CH Energy Group's Consolidated Statement of Comprehensive Income.

The Financial Statements were prepared in conformity with accounting principles generally accepted in the United States of America ("GAAP"), which for regulated public utilities, includes specific accounting guidance for regulated operations. For additional information regarding regulatory accounting, see Note 3 – "Regulatory Matters."

Regulatory Accounting Policies

Regulated companies such as Central Hudson defer costs and credits on the balance sheet as regulatory assets and liabilities (see Note 3 – "Regulatory Matters") when it is probable that those costs and credits will be recoverable through the rate-making process in a period different from when they otherwise would have been reflected in income. For Central Hudson, these deferred regulatory assets and liabilities, and the related deferred taxes, are then either eliminated by offset as directed by the PSC or reflected in the Consolidated Statement of Income in the period in which the same amounts are reflected in rates. In addition, current accounting practices reflect the regulatory accounting authorized in the most recent settlement agreement or rate order, whichever the case may be.

Use of Estimates

Preparation of the financial statements in accordance with GAAP includes the use of estimates and assumptions by management that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. As with all estimates, actual results may differ from those estimated. Expense items most affected by the use of estimates are depreciation and amortization (including amortization of intangible assets), reserves for uncollectible accounts receivable, tax reserves, other operating reserves, unbilled revenues, and pension and other post-retirement benefits.

- Depreciation and amortization is based on estimates of the useful lives and estimated net salvage value of properties (as described in Note 2 – "Utility Plant – Central Hudson").
- Estimates for uncollectible accounts are based on customer accounts receivable aging data as well as consideration of various quantitative and qualitative factors, including special collection issues.
- The tax reserve recorded by Central Hudson relates to a change in 2010 to its tax return methodology for claiming deductions for incidental repair and maintenance expenditures on its utility assets. Although Management believes that its methodology for claiming the deduction is consistent with the Internal Revenue Code and case law, Management cannot predict whether the Internal Revenue Service will accept the entirety of the deduction claimed. See Note 4 – "Income Tax" for further discussion of the tax reserve established.
- The estimates for other operating reserves are based on assessments of future obligations related to injuries and damages and workers' compensation claims.
- Unbilled revenues are determined based on the estimated sales for bimonthly accounts that have not been billed by Central Hudson in the current month. The estimation methods used in determining these sales are the same methods used for billing customers when actual meter readings cannot be obtained. Estimated unbilled revenues are reported as current assets, and include amounts recorded both in revenues and recorded as regulatory liabilities. Revenues include an estimate for approximately 1 month of unbilled revenues due to Central Hudson's bi-monthly billing cycle, which was $10.7 million for 2015, $11.0 million for 2014 and $11.2 million for 2013, respectively. Pursuant to regulatory requirements, the remaining portion of unbilled revenue through the period end reporting date is recorded as a regulatory liability and is not included in revenues.
- The significant assumptions and estimates used to account for the pension plan and other post-retirement benefit expenses and liabilities are the discount rate, the expected long-term rate of return on the retirement plan and post-retirement plan assets, the rate of compensation increase, the healthcare cost trend rate, mortality assumptions, and the method of amortizing gains and losses. For more information of the significant assumptions and estimates, see Note 10 – "Post-Employment Benefits."
- Estimates are also reflected for certain commitments and contingencies where there is sufficient basis to project a future obligation. Disclosures related to these certain

commitments and contingencies are included in Note 12 - “Commitments and Contingencies.”

Rates, Revenues, and Cost Adjustment Clauses

Central Hudson’s electric and natural gas retail rates are regulated by the NYS Public Service Commission (“PSC”). Transmission rates, facilities charges, and rates for electricity sold for resale in interstate commerce are regulated by the Federal Energy Regulatory Commission (“FERC”).

Central Hudson’s tariffs for retail electric and natural gas service include purchased electricity and purchased natural gas cost adjustment clauses by which electric and natural gas rates are adjusted to collect the actual purchased electricity and purchased natural gas costs incurred in providing these services.

Central Hudson’s delivery rate structure includes Revenue Decoupling Mechanisms (“RDMs”), which provide the ability to record revenues equal to those forecasted in the development of current rates for most of Central Hudson’s customers.

Revenue Recognition

Central Hudson records revenue on the basis of meters read. In addition, Central Hudson records an estimate of unbilled revenue for service rendered to bimonthly customers whose meters are read in the prior month. The estimate covers 30 days subsequent to the meter read date. Prior to July 1, 2015, pursuant to regulatory requirements, a portion of unbilled electric revenues was not recorded. As of December 31, 2014 and December 31, 2013, the portion of estimated electric unbilled revenues that was unrecognized in accordance with then current regulatory agreements were $13.1 million and $13.0 million, respectively. On July 1, 2015, per the Order Approving Rate Plan (“2015 Rate Order”) in Cases 14-E-0318 and 14-G-0319, Central Hudson was granted authorization to record all unbilled electric revenues and defer the residual unbilled revenue greater than the 30 day estimate. The full amounts of estimated natural gas unbilled revenues are recognized on the Balance Sheets in all periods presented and as of December 31, 2015 for estimated electric unbilled revenues.

As required by the PSC, Central Hudson records gross receipts tax revenues and expenses on a gross income statement presentation basis (i.e., included in both revenue and expenses). Sales and use taxes for Central Hudson are accounted for on a net basis (excluded from revenue).

Cash and Cash Equivalents

For purposes of the Statement of Cash Flows and the Balance Sheet, CH Energy Group and Central Hudson consider temporary cash investments with a maturity (when purchased) of three months or less, to be cash equivalents.

Restricted Cash

Restricted cash in CH Energy Group and Central Hudson’s Balance Sheets in “Special Deposits and Prepayments” was $1.0 million at December 31, 2015. There was no restricted cash at December 31, 2014. Restricted cash primarily consists of cash collected from developers and held in escrow related to a potential System Delivery upgrade project pursuant to terms and conditions of the New York Independent System Operator's ("NYISO") Open Access Transmission Tariff.

Inventory

Inventory consists of fuel, materials and supplies for CH Energy Group and Central Hudson and is valued using the average cost method.

The following is a summary of CH Energy Group's and Central Hudson's inventories (In Thousands):

	December 31, 2015	December 31, 2014
Natural gas	$ 5,148	$ 6,323
Fuel used in electric generation	482	403
Materials and supplies	13,153	10,820
Total	$ 18,783	$ 17,546

Utility Plant - Central Hudson

The regulated assets of Central Hudson include electric, natural gas, and common assets and are listed under the heading "Utility Plant" on Central Hudson's and CH Energy Group's Consolidated Balance Sheets. The accumulated depreciation associated with these regulated assets is also reported on the Balance Sheets.

The cost of additions to utility plant and replacements of retired units of property are capitalized at original cost. Capitalized costs include labor, materials and supplies, indirect charges for such items as transportation, certain administrative costs, certain taxes, pension and other employee benefits, and allowances for funds used during construction ("AFUDC"); less contributions in aid of construction.

The replacement of minor items of property is included in operating expenses.

The original cost of property, together with removal cost less salvage, is charged to accumulated depreciation at the time the property is retired and removed from service as required by the PSC.

For additional information see Note – 2 "Utility Plant – Central Hudson."

Depreciation and Amortization

For financial statement purposes, Central Hudson's depreciation provisions are computed on the straight-line method using PSC approved rates based on studies of the estimated useful lives and estimated net salvage values of properties. The anticipated costs of removing assets upon retirement are generally provided for over the life of those assets as a component of depreciation expense. In accordance with current accounting guidance for regulated operations, Central Hudson accrues for the future cost of removal for its rate-regulated natural gas and electric utility assets by recording a regulatory liability for the portion of the cost of removal. This depreciation method is consistent with industry practice and is not allowed to be shown as accumulated depreciation in accordance with GAAP. Therefore, a reclassification to regulatory liabilities for reporting purposes is required.

Central Hudson performs depreciation studies periodically and, upon approval by the PSC, adjusts the depreciation rates of its various classes of depreciable property. Central Hudson's composite rates for depreciation were 2.73% in 2015, 2.86% in 2014 and 2.77% in 2013 of the original average cost of depreciable property. The ratio of the amount of accumulated depreciation to the original cost of depreciable property at December 31, 2015, 2014, and 2013 was 26.1%, 26.6% and 26.4%, respectively.

Asset Retirement Obligations

Each Asset Retirement Obligation ("ARO") is recorded as a liability at fair value, with a corresponding increase to utility capital assets. Central Hudson recognizes AROs in the periods in which they are known and estimable. The fair value of AROs is based on an estimate of the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to reflect the passage of time and any changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities.

Current accounting guidance related to asset retirement, precludes the recognition of expected future retirement obligations as a component of depreciation expense or accumulated depreciation. Central Hudson, however, is required to use depreciation methods and rates approved by the PSC under regulatory accounting. These depreciation rates include a charge for the cost of future removal and retirement of fixed assets.

Impairment of Long-Lived Assets

Central Hudson reviews long lived assets for impairment. Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair rate of return, is provided through customer electricity and gas rates approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific, but are pooled for the entire regulated utility.

Allowance For Funds Used During Construction

Central Hudson's regulated utility plant includes AFUDC, which is defined as the net cost of borrowed funds used for construction purposes and a reasonable rate on other funds when so used. The concurrent credit for the amount so capitalized is reported in the Consolidated Statement of Income as follows: the portion applicable to borrowed funds is reported as a reduction of interest charges while the portion applicable to other funds (the equity component, a noncash item) is reported as other income. The AFUDC rate was 6.2% in 2015, 4.6% in 2014 and 5.0% in 2013.

Operating Leases

CH Energy Group and its subsidiaries recognize operating lease payments as an expense in the Statement of Income on a straight line basis over the lease term.

Research and Development

Central Hudson is engaged in the conduct and support of research and development ("R&D") activities, which are focused on the improvement of existing energy technologies and the development of new technologies for the delivery and customer use of energy. R&D expenditures are provided for in Central Hudson's rates charged to customers for electric and natural gas delivery service, with any differences between R&D expense and the rate allowances deferred for future recovery from or return to customers. See Note 6 – "Research and Development" for additional details.

Deferred Financing Costs

Expenses incurred in connection with CH Energy Group's or Central Hudson's debt issuance and any discount or premium on debt are deferred and amortized over the lives of the related issues. When Long-term debt is reacquired or redeemed, regulatory accounting permits deferral of related unamortized debt expense and reacquisition costs. These costs are being amortized over the remaining life of the original life of the debt issue retired. The amortization of debt costs for reacquired debt is incorporated in the revenue requirement for delivery rates as authorized by the PSC.

Income Tax

CH Energy Group and its subsidiaries file consolidated federal and state income tax returns. Income taxes are deferred under the asset and liability method in accordance with current accounting guidance for income taxes, resulting in deferred income taxes for all differences between the financial statement and the tax basis of assets and liabilities. Additional deferred income taxes and offsetting regulatory assets or liabilities are recorded by Central Hudson to recognize that income taxes will be recovered or refunded through future revenues. For federal and state income tax purposes, CH Energy Group and its subsidiaries use an accelerated method of depreciation and generally use the shortest life permitted for each class of assets. Deferred investment tax credits are amortized over the estimated life of the properties giving rise to the credits. For state income tax purposes, Central Hudson uses book depreciation for property placed in service in 1999 or earlier in accordance with transition property rules under Article 9-A of the New York State Tax Law. CHEC files state income tax returns in the states in which it conducts business. For more information, see Note 4 – "Income Tax." Central Hudson follows the normalization method of accounting whereas the tax benefits associated with utility assets are spread over the same time period that the costs of those assets are recovered from customers. Normalization is required as a prerequisite for utilities claiming accelerated depreciation and certain tax credits.

Post-Employment and Other Benefits

Central Hudson sponsors a noncontributory Retirement Income Plan (“Retirement Plan”) for substantially all management, professional and supervisory employees hired before January 1, 2008 and for all Union employees hired before May 1, 2008. Benefits are based on years of service and compensation. In addition, Central Hudson provides Other Post Retirement Benefits (“OPEB”) which include limited health care and life insurance benefits for retirees hired within the same time period as stated above. Additionally, Central Hudson maintains a Supplemental Executive Retirement Plan (“SERP”) for certain members of management.

Central Hudson recognizes the underfunded status of the defined benefit pension plans as a liability on the balance sheets. The underfunded status is measured as the difference between the fair value of the pension plans’ assets and the projected benefit obligation for the pension plans. Central Hudson recognizes a regulatory asset for the underfunded amount because these future costs are probable of recovery in the rates charged to customers and Central Hudson expects to recover these costs over the estimated service lives of employees.

Retirement Plan and OPEB assets are valued under the current fair value framework. See Note 14 – “Accounting for Derivative Instruments and Hedging Activities” for further discussion regarding the definition and levels of fair value hierarchy established by accounting guidance.

Retirement Plan and OPEB benefit expenses are determined by actuarial valuations based on assumptions that Central Hudson evaluates annually.

Central Hudson sponsors a contributory plan, the 401(k) retirement plan (“401(k) plan”) for its employees. The 401(k) plan provides for employee tax-deferred salary deductions for participating employees and employer match contributions.

For more information see Note 10 – “Post-Employment Benefits”.

Equity-Based Compensation

Central Hudson has Share Unit Plans (“SUPs”) that grant share units to CH Energy Group and Central Hudson’s officers as part of the officers’ total compensation. Central Hudson records the compensation expense and liability associated with the SUPs based on the fair value at each reporting date until settlement reflecting expected future payout and time elapsed within the terms of the award. The fair value of the SUPs’ liability is based on the Fortis’ common share 5 day volume weighted average trading price at the end of each reporting period. For more information, see Note 11 – “Equity-Based Compensation”.

Common Stock Dividends

CH Energy Group’s ability to pay dividends is affected by the ability of its subsidiaries to pay dividends. The Federal Power Act limits the payment of annual dividends by Central Hudson to its retained earnings. More restrictive is the PSC’s limit on the dividends Central Hudson may pay to CH Energy Group, which is 100% of the average annual income available for common stock, calculated on a two-year rolling average basis. See Note 8 – “Capitalization-Common and Preferred Stock” for information regarding dividends declared.

Derivatives

From time to time, Central Hudson enters into derivative contracts in conjunction with the Company's energy risk management program to hedge certain risk exposure related to its business operations. Central Hudson uses derivative contracts to reduce the impact of volatility in the prices of natural gas and electricity and to hedge exposure to volatility in interest rates for its variable rate long-term debt.

Realized gains and losses on Central Hudson's derivative instruments are conveyed to or recovered from customers through PSC-authorized deferral accounting mechanisms, with no material impact on cash flows, results of operations or liquidity. Realized gains and losses on Central Hudson's energy derivative instruments are reported as part of purchased natural gas, purchased electricity and fuel used in electric generation in Central Hudson's and CH Energy Group's Statements of Income as the corresponding amounts are either recovered from or returned to customers through fuel cost adjustment clauses in revenues. See Note 14 – "Accounting for Derivative Instruments and Hedging Activities" for further details.

Normal Purchases and Normal Sales

Central Hudson enters into forward energy purchase and sales contracts, including options, with counterparties that have generating capacity to support current load forecasts or counterparties that have load serving requirements. Central Hudson has elected the normal purchase or normal sales exception for these contracts, which are not required to be measured at fair value and are accounted for on an accrual basis. See Note 12 – "Commitments and Contingencies" for further details.

Reclassification

Certain amounts in the 2014 Financial Statements have been reclassified to conform to the 2015 presentation on CH Energy Group or Central Hudson's financial statements. See below "New Accounting Policies" for further details.

New Accounting Policies

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period
Effective January 1, 2015, Central Hudson and CH Energy Group early adopted ASU No. 2014-12 that resolves diversity in practice for employee share-based payments with performance targets that allow an employee to benefit from an award regardless of whether the employee is rendering services at the date the performance target is achieved. This update was applied prospectively and did not have a material impact on the financial statements.

Simplifying the Presentation of Debt Issuance Costs
Effective October 1, 2015, Central Hudson and CH Energy Group early adopted ASU No. 2015-03 that requires debt issuance costs to be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The adoption of this update was applied retrospectively and resulted in the reclassification of debt issuance costs of approximately $4.1 million from long-term other assets to long-term debt on the Central Hudson and CH Energy Group consolidated balance

sheet at December 31, 2014. In addition, Central Hudson and CH Energy Group early adopted ASU No. 2015-15 that clarifies the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements. The update permits an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. This update was applied retrospectively and did not have a material impact on the financial statements.

Balance Sheet Classification of Deferred Taxes
Effective October 1, 2015, Central Hudson and CH Energy Group early adopted ASU No. 2015-17 that requires deferred tax assets and liabilities to be classified and presented as long term on the consolidated balance sheet. The adoption of this update was applied retrospectively and resulted in the reclassification from current to long-term of deferred income tax assets of $5.6 million for Central Hudson and $12 million for CH Energy Group at December 31, 2014. There was no reclassification of deferred income tax liabilities from current to long term for Central Hudson or CH Energy Group at December 31, 2014.

NOTE 2 – Utility Plant - Central Hudson

Utility Plant

The following summarizes the type and amount of assets included in the electric, natural gas, and common categories of Central Hudson's utility plant balances:

	Estimated Depreciable Life in Years	Utility Plant December 31, 2015	2014
Electric:		(In Thousands)	
Production	25-85	$ 37,967	$ 37,964
Transmission	30-80	299,078	274,155
Distribution	7-80	889,404	844,438
Other	40	4,214	4,086
Total		$ 1,230,663	$ 1,160,643
Natural Gas:			
Transmission	19-80	56,075	53,800
Distribution	28-95	360,938	326,724
Other	N/A	442	442
Total		$ 417,455	$ 380,966
Common:			
Land and Structures	50	$ 68,683	$ 66,750
Office and Other Equipment, Radios and Tools	8-35	44,611	42,760
Transportation Equipment	10-12	57,381	53,936
Other	5-10	30,518	21,358
Total		$ 201,193	$ 184,804
Gross Utility Plant		$ 1,849,311	$ 1,726,413

Total AFUDC borrowed for 2015 was $0.6 million and $0.4 million in both 2014 and 2013, respectively. The equity component of AFUDC recorded for the year 2015 was $1.2 million and $0.6 million in both 2014 and 2013, respectively.

Included in the Net Utility Plant balance of $1,422 million and $1,326 million at December 31, 2015 and 2014 is $58.8 million, and $50.9 million of intangible utility plant assets and the related accumulated amortization of $26.0 million and $23.0 million, respectively.

As of December 31, 2015 and 2014, Central Hudson has classified $46.6 million and $47.8 million of cost of removal charged in excess of the amount reported as an ARO under GAAP as a regulatory liability.

As of December 31, 2015 and 2014, AROs for Central Hudson were approximately $1.0 million and $1.2 million, respectively. These amounts have been classified in the above chart under "Electric - Other" and "Common - Other" based on the nature of the ARO and is also reflected as "Other" long-term liabilities in the CH Energy Group and Central Hudson Balance Sheets.

NOTE 3 – Regulatory Matters

The PSC approved a settlement agreement (the “Settlement Agreement”) between Central Hudson, PSC staff and certain other parties in Case 96-E-0909 on February 19, 1998 that was subsequently amended on June 30, 1998, March 7, 2000 and, in case 12-M-0192 on June 26, 2013.

The Settlement Agreement included the following major provisions which survived its expiration date: (i) certain limitations on ownership of electric generation facilities by Central Hudson and its affiliates in Central Hudson’s franchise territory; (ii) standards of conduct in transactions between Central Hudson, CH Energy Group, and other affiliates of CH Energy Group; (iii) prohibitions against Central Hudson making loans to CH Energy Group or any other subsidiary of CH Energy Group and against Central Hudson guaranteeing debt of CH Energy Group or any other subsidiary of CH Energy Group; (iv) Credit quality and dividend restrictions; (v) Special class of preferred stock relating to bankruptcy; (vi) Financial transparency and reporting; (vii) Corporate governance and operational provisions; (viii) limitations on the transfer of Central Hudson employees to CH Energy Group or other CH Energy Group affiliates; (ix) certain dividend payment restrictions on Central Hudson; and (x) treatment of savings up to the amount of an acquisition’s or merger’s premium or costs flowing from a merger with another utility company.

Summary of Regulatory Assets and Liabilities

The following table sets forth Central Hudson's regulatory assets and liabilities (In Thousands):

	December 31. 2015		December 31. 2014	
Regulatory Assets (Debits):				
Current:				
Deferred purchased electric costs (Note 1)	$ 8,154		$ 21,643	
Deferred purchased natural gas costs (Note 1)	1,233		7,839	
Deferred unrealized losses on derivatives - Electric (Note 14)	9,152		5,873	
Deferred unrealized losses on derivatives - Gas (Note 14)	990		1,854	
PSC General and Temporary State Assessment and carrying charges	4,139	(1)	2,665	
RDM and carrying charges - Electric	-		5,661	
Deferred debt expense on re-acquired debt	520		520	
Deferred and accrued costs - MGP site remediation (Note 12)	6,242		4,605	
Deferred storm costs and carrying charges	-	(1)	5,113	
Other	358	(1)	118	
	$ 30,788		$ 55,891	
Long-term:				
Deferred pension costs (Note 10)	$ 94,488	(1)	$ 94,426	
Deferred unrealized losses on derivatives - Electric (Note 14)	1,476		-	
Carrying charges - pension reserve	1,181	(1)	16,904	
Deferred and accrued costs - MGP site remediation and carrying charges (Note 12)	80,959	(1)	101,199	
Deferred debt expense on re-acquired debt	3,938		4,458	
Deferred Medicare Subsidy taxes	-	(1)	8,931	
Residual natural gas deferred balances and carrying charges	-	(1)	1,130	
Income taxes recoverable through future rates	29,734		35,121	
Energy efficiency incentives and carrying charges	5,061		2,792	
Deferred property taxes and carrying charges	541	(1)	4,019	
Deferred storm costs and carrying charges	5,281		-	
Other	11,995	(1)	21,130	
	$ 234,654		$ 290,110	
Total Regulatory Assets	$ 265,442		$ 346,001	
Regulatory Liabilities (Credits):				
Current:				
Rate moderator - Electric	$ 12,655		$ -	
Rate moderator - Gas	3,411		-	
RDM and carrying charges - Electric	5,419		-	
RDM and carrying charges - Gas	3,492		5,297	
Deferred unbilled electric and gas revenues (Note 1)	17,452		5,962	(2)
	$ 42,429		$ 11,259	
Long-term:				
Rate moderator - Electric and carrying charges	$ 40,778		$ -	
Rate moderator - Gas and carrying charges	6,423		-	
Customer benefit fund	5,665		6,271	
Deferred cost of removal (Note 2)	46,561		47,832	
Rate Base impact of tax repair project and carrying charges	-	(1)	13,402	
Excess electric depreciation reserve carrying charges	-	(1)	1,586	
Deferred unrealized gains on derivatives - Electric (Note 14)	2,218		570	
Income taxes refundable through future rates	23,810	(1)	28,607	
Deferred OPEB costs (Note 10)	25,663	(1)	47,339	
Carrying charges - OPEB reserve	1,384	(1)	20,991	
PBA - Electric and carrying charges	-	(1)	13,005	
PBA - Gas and carrying charges	-	(1)	3,299	
Other	6,149	(1)	25,709	
	$ 158,651		$ 208,611	
Total Regulatory Liabilities	$ 201,080		$ 219,870	
Net Regulatory Assets/Liabilities	$ 64,362		$ 126,131	

(1) Central Hudson offset all or a portion of certain regulatory assets and liabilities as of June 30, 2015 in accordance with the PSC prescribed 2015 Rate Order ("2015 Rate Order") issued on June 17, 2015.

(2) Prior to July 1, 2015, pursuant to regulatory requirements, unbilled electric revenues were not recorded. Amounts reported as of December 31, 2014 consists only of estimated natural gas unbilled revenues.

The significant regulatory assets and liabilities not referenced in other notes to the financial statement include:

Rate Moderator – Electric and Gas: Under the terms of the 2015 Rate Order, certain regulatory assets and liabilities were identified for offset and a regulatory liability was established with the net balance, which will be used for future customer rate moderation ("Rate Moderator"). In addition, per the 2015 Rate Order, Central Hudson is required to defer actual delivery revenues associated with providing gas to Danskammer Generating Station which are to be used for future Rate Moderation. The current portion of the Rate Moderator represents the amount estimated to be used for rate moderation in the next twelve months related to customer electric and gas bill credits as prescribed in the 2015 Rate Order.

PSC General and Temporary State Assessment: In April 2009, the PSC issued an order instituting a new Temporary New York State Assessment ("NYSA") to be collected through utility bills as mandated by NYS over five years from July 1, 2009 through June 30, 2014. In 2013, the NYSA was extended through March 31, 2017. Central Hudson is required to make bi-annual payments of this assessment, in conjunction with its payments of the PSC General Assessment, and to collect the amount from customers in subsequent months. Deferral accounting for both these assessments was authorized in this order.

Revenue Decoupling Mechanism ("RDMs"): Effective July 1, 2009 and continuing in the 2010 Order Establishing Rate Plan issued by the PSC Central Hudson on June 18, 2010 ("2010 Rate Order") and Order Authorizing Acquisition Subject to Conditions ("2013 Joint Petition") through June 30, 2015, Central Hudson's delivery rate structure includes RDMs, which provide the ability to record revenues equal to those forecasted in the development of current rates for most of Central Hudson's customers. The difference between actual revenues and forecasted revenues are deferred for future recovery from or refund to customers with the deferred balance subject to carrying charges at the Other Customer Deposit Rate approved annually by the PSC.

Residual Natural Gas Deferred Balances: As a result of the 2009 Order Establishing Rate Plan issued by the PSC to Central Hudson on June 22, 2009 ("2009 Rate Order") and the 2010 Rate Order, certain gas regulatory assets and liabilities were identified for offset and the establishment of a net regulatory asset to be amortized over a PSC-approved time period. This balance was fully amortized by the time new rates went into effect on July 1, 2015.

Deferred Debt Expense on Reacquired Debt: When long-term debt is reacquired or redeemed, regulatory accounting permits deferral of related unamortized debt expense and reacquisition costs. These costs are being amortized over the remaining life of the original life of the issue retired. The amortization of debt costs for reacquired or redeemed debt is incorporated in the revenue requirement for delivery rates as authorized by the PSC.

Carrying Charges - Pension Reserve: Under the policy of the PSC regarding pension costs, carrying charges are accrued on cash differences between rate allowances and cash contributions to Central Hudson's defined benefit pension plan. For further discussion regarding this plan, see Note 10 – "Post-Employment Benefits."

Deferred Medicare Subsidy Taxes: The Patient Protection and Affordable Care Act signed into law on March 23, 2010, contains a provision which changes the tax treatment related to the

Retiree Drug Subsidy benefit under the Medicare Prescription Drug, Improvement and Modernization Act (under Medicare Part D). This change reduces the employer's deduction for the costs of health care for retirees by the amount of Retiree Drug Subsidy payments received. As a result, the deductible temporary difference and any related deferred tax asset associated with the benefit plan were reduced. Under the PSC policy regarding Medicare Act Effects, cost savings and income tax effects related to the Medicare Prescription Drug, Improvement and Modernization Act are deferred for future recovery from or refund to customers. Per the 2015 Rate Order, this balance was offset at June 30, 2015 in the establishment of the Rate Moderator - Electric and Gas balance. In addition, rates effective July 1, 2015, take into account the proper tax treatment of the Medicare subsidy and therefore no additional amounts are expected to be deferred.

Deferred Property Taxes: In accordance with the 2013 Rate Order and continuing in the 2015 Rate Order, Central Hudson is authorized to defer for the benefit of or recovery from customers, 90% of any difference between actual property tax expense and the amounts provided in rates for each Rate Year. Central Hudson's portion of the difference is limited to a maximum of $0.9 million per Rate Year.

Income Taxes Recoverable: This regulatory asset has been established to offset certain deferred tax liabilities because Management believes it is probable that they will be recoverable from customers.

Energy Efficiency Incentives: In 2008, Central Hudson received approval through the Energy Efficiency Portfolio Standard ("EEPS") proceedings to implement various programs for electric and natural gas residential and commercial customers. In December 2010, the PSC issued an order combining energy savings targets to create a single 2009-2011 target. In 2011, Central Hudson earned $2.7 million in incentives under the 2009-2011 defined targets. In 2012, the PSC issued a separate order establishing a single target for 2012-2015. As of December 31, 2015, Central Hudson earned approximately $2.1 million of electric and $0.2 million of gas incentives under the 2012-2015 defined targets.

Storm Costs: Central Hudson is authorized to request and the PSC has historically approved deferral accounting for incremental storm restoration costs which meet the following criteria: (1) the expense must be incremental to the amount provided in rates, (2) the incremental costs must be material and extraordinary in nature, and (3) the company's earnings cannot be in excess of the authorized regulatory rate of return. As of December 31, 2015, Central Hudson has deferred $5.3 million of incremental costs incurred for the restoration of electric service to customers following the impact of the November 27, 2014 storm ("2014 Thanksgiving Storm" or "SnowBird"). Central Hudson filed a petition with the PSC on August 7, 2015 seeking Commission approval to recover the incremental electric storm restoration expense associated with SnowBird, with carrying charges. On January 21, 2016, under Case 15-E-0464, the PSC approved the deferral of incremental storm restoration costs together with carrying charges at the allowed pre-tax rate of return. Recovery of these costs has been postponed until the next rate filing.

Positive Benefit Adjustment ("PBA"): Under the 2013 Joint Petition, a $35 million PBA was established to cover expenses normally required to be recovered from ratepayers. In accordance with the order, storm restoration costs of approximately $20.1 million, for storm costs associated with Tropical Storm Irene, the October 2011 snow storm and Superstorm

Sandy were offset by the PBA. At June 30, 2015, the remaining balance was offset in accordance with the 2015 Rate Order for the establishment of the Rate Moderator - Electric and Gas balance.

Income Taxes Refundable: This regulatory liability was established to offset certain deferred tax assets because Management believes it is probable that the related balances will be refundable to customers.

Customer Benefit Fund: The 2010 Order prescribed the use of the residual balance to fund economic development.

Rate Base Impact of Tax Repair Project: In April 2011, the PSC approved the ratemaking treatment to offset certain incremental storm costs and incremental bad debt expense deferrals with tax refunds resulting from a change in tax return methodology for claiming deductions for incidental repair and maintenance expenditures on its utility assets. The remaining balance of the tax refund not subject to offset has been established as a regulatory liability subject to carrying charges for the benefit of customers. At June 30, 2015, the balance was offset in accordance with the 2015 Rate Order for the establishment of the Rate Moderator - Electric and Gas balance.

Excess Electric Depreciation Reserve ("EDR"): Under the 2006 Rate Order, a $40M regulatory liability balance was established and was subject to carrying charges at the pre-tax weighted average cost of capital. Under the 2006, 2009 and 2010 Rate Order, this balance was approved for use in rate moderation. The EDR regulatory liability had been fully utilized, however, the carrying charges accumulated remained as a regulatory liability balance until June 30, 2015, when the remaining balance was offset in accordance with the 2015 Rate Order for the establishment of the Rate Moderator - Electric and Gas balance.

Carrying Charges - OPEB Reserve: Under the policy of the PSC regarding OPEB costs, carrying charges are accrued on cash differences between rate allowances and cash contributions to Central Hudson's OPEB plan. For further discussion regarding this plan, see Note 10 – "Post-Employment Benefits."

In terms of the expected timing for recovery, regulatory asset balances at December 31, 2015, reflect the following (In Thousands):

		December 31, 2015
Balances with offsetting accrued liability balances recoverable when future costs are actually incurred:		
Deferred pension related to underfunded status	$	91,161
Income taxes recoverable through future rates		29,734
Deferred unrealized losses on derivatives		11,618
Deferred costs - MGP sites		92,119
Other		5,909
		230,541
Balances earning a return via inclusion in rates and/or the application of carrying charges:		
Deferred property taxes		518
PSC - General and temporary state assessment		4,015
Deferred storm costs		4,991
Deferred debt expense on re-acquired debt		4,458
Other(1)		4,438
		18,420
Subject to current recovery:		
Deferred purchased electric costs		8,154
Deferred purchased natural gas costs		1,233
Other		195
		9,582
Other:		
Energy efficiency incentives(1)		4,984
Other		193
		5,177
Accumulated carrying charges:(1)		
Pension reserve		1,181
Other		541
		1,722
Total Regulatory Assets	$	265,442

(1) Subject to recovery in Central Hudson's future rate proceedings.

2013 Acquisition Order/2015 Rate Order

From July 1, 2010 through June 30, 2013, Central Hudson operated under the terms of the 2010 Rate Order. On June 26, 2013 the PSC issued its Order Authorizing Acquisition Subject to Conditions in Case 12-M-0192 (the “2013 Acquisition Order”), which was accepted on June 27, 2013. The 2013 Acquisition Order adopted the terms of the 2013 Joint Proposal dated January 25, 2013 for the acquisition of CH Energy Group, owner of Central Hudson, by Fortis along with additional commitments by the companies to enhance financial protection for ratepayers and other community and economic development benefits. The 2013 Acquisition Order included a 2 year rate freeze on electric and natural gas delivery rates and extended certain terms of the 2010 Rate Order through June 30, 2015. The 2015 Rate Order adopted the terms set forth in the April 22, 2015 Joint Proposal. The 2015 Rate Order became effective July 1, 2015, with Rate Year 1, Rate Year 2 and Rate Year 3 defined as the twelve months ending June 30, 2016, June 30, 2017 and June 30, 2018, respectively. A summary of the key terms of the 2013 Joint Proposal and 2015 Rate Order are as follows:

Description	2013 Acquisition Order	2015 Rate Order Rate Year 1	2015 Rate Order Rate Year 2	2015 Rate Order Rate Year 3
Electric delivery rate increases	$0 through June 30, 2015	$15.3 Million	$16.0 Million	$14.1 Million
Natural gas delivery rate increases	$0 through June 30, 2015	$1.8 Million	$4.6 Million	$4.4 Million
ROE	10.00%	9.00%	9.00%	9.00%
Earnings sharing	Yes(1)	Yes(2)	Yes(2)	Yes(2)
Capital structure – common equity	48%	48%	48%	48%
Positive benefit adjustments	$35.0 million(3)	N/A	N/A	N/A
Community benefit fund	$5.0 million(3)	N/A	N/A	N/A
Bill Credits - Electric	N/A	$13.0 Million	$12.0 Million	$2.0 Million
Bill Credits - Gas	N/A	$2.548 Million	$1.7 Million(5)	$0(5)
Major Storm Reserve - Electric	N/A	$0.7 Million	$0.7 Million	$0.7 Million
Synergy Savings	$1.85 million(4)	N/A	N/A	N/A
RDMs – electric and natural gas	Yes	Yes	Yes	Yes

(1) ROE > 10.0% and up to 10.5%, 50% to customers, > 10.5%, 90% to customers.
(2) ROE > 9.5% and up to 10.0%, 50% to customers, > 10.0% and up to 10.5%, 80% to customers, > 10.5%, 90% to customers.
(3) To cover expenses typically recovered from rate payers, such as storm restoration costs and for economic development and low-income customer assistance programs.
(4) Guaranteed annual synergy savings of $1.85 million to ratepayers for 5 years.
(5) In addition to gas bill credits, 50% of gas delivery revenues from the Danskammer Generating Station in RY1 will be refunded to customers via bill credit in RY2. In addition, 50% of revenues from RY2 will be refunded as a gas bill credit in RY3.

Other key provisions of the 2015 Rate Order include:

- The Rate Order provides for partial or full reconciliation of certain expenses including, but not limited to: property taxes, pensions/OPEBs, environmental site investigation and remediation costs, variable and fixed rate debt, and stray voltage. In addition, the Rate Order includes downward-only reconciliations for net plant, distribution and transmission right-of-way maintenance costs, security costs and rate case expenses. The Rate Order also authorizes a continuation of full cost recovery of electric and natural gas commodity costs.

- Central Hudson's Customer Service Quality Performance Mechanisms (consisting of the PSC Annual Compliant Rate, the Customer Satisfaction Index and Appointments Kept measures) and more stringent electric reliability and gas safety performance metrics continue. The Company will be subject to a negative revenue adjustment if it fails to meet specific metrics as set forth in the Rate Order.

- The Rate Order directs Central Hudson to replace or eliminate 13 miles of leak prone pipe in calendar year 2016, 14 miles in 2017, and 15 miles in 2018. In the event the Company fails to meet its leak prone pipe target in any calendar year, the Company will be subject to an 8 basis point negative revenue adjustment. The Rate Order also limits the amount provided in rates associated with the replacement of leak prone pipes. The Rate Order provides the Company with an incentive to surpass its leak prone pipe target for a positive revenue adjustment for each mile replaced or eliminated in excess of the applicable target, capped at maximum of 5 miles for a total of 10 basis points per calendar year, which the Company will defer for future recovery.

- The Rate Order provides for a $1 million annual program funding each Rate Year to provide additional incentives and support for customer conversion to gas. Central

Hudson will receive an annual incentive in the form of 1 basis point for every 200 gas customers added above the combined total customer count forecast for residential and commercial customers for each Rate Year.

- The Rate Order directs the Company to transition to monthly billing for all customers by July 2016.

- The Rate Order provides for Network Strategy and Distribution Automation capital expenditures. Full implementation of the Network Strategy and Distribution Automation project beyond Rate Year 1 will be dependent upon the PSC agreement that the Company has successfully demonstrated the functional capability and operation/integration of these investments.

Other PSC Proceedings

On August 7, 2015, Central Hudson filed a petition with the PSC seeking recovery of $5.284 million of incremental electric storm restoration expense plus carrying charges incurred during the twelve months ended June 30, 2015, from the 2014 Thanksgiving Storm. These incremental costs represent the amount Central Hudson deferred on its books based on actual costs incurred and bills received. The Company believes the incremental costs associated with the SnowBird storm meet the PSC's criteria for deferral: 1) the amount is incremental to the amount provided in rates; 2) the incremental amount is material and extraordinary in nature; and 3) the utility's earnings are below the authorized rate of return on common equity. On January 21, 2016, under Case 15-E-0464, the PSC approved the deferral of incremental storm restoration costs together with carrying charges at the allowed pre-tax rate of return. Recovery of these costs is postponed until the next rate filing.

Deferral of incremental costs exceeding 2% of net income related to governmental mandates was authorized in the 2010 Rate Order, Case 09-E-0588 and was extended for two additional rate years in Case 12-M-0192. In the current period there are two regulatory asset balances that are deferrals under this clause:

- In February 2014, the PSC issued an Order requiring risk assessments and remediation of certain NYS gas facilities to identify conditions similar to those found in a natural gas explosion that occurred in Horseheads, New York in 2011. In May 2014, the PSC issued a modifying Order in this proceeding extending the deadline for utilities to complete risk assessments until February 2015 and adding a requirement effective August 2014 for utilities to report to the PSC on the progress of their risk assessments every 45 days. On December 5, 2014, Central Hudson filed a request for an extension of the deadline for submitting its Risk Assessment until September 30, 2015. In response to requests filed by the utilities, on February 19, 2015 the PSC issued a Notice Extending Deadline to Submit Risk Assessment to September 30, 2015. Central Hudson filed its Risk Assessment and Risk Mitigation Plan with the PSC on September 1, 2015. The Horseheads deferral petition was filed with the PSC on October 14, 2015. The incremental amount Central Hudson has deferred on its books as of December 31, 2015 is $2.2 million, including carrying charges.

- On September 1, 2015, Central Hudson filed a petition with the PSC seeking approval for recovery of incremental costs, including internal labor and related carrying charges associated with new compliance requirements resulting from the North American Electric Reliability Corporation's ("NERC's") change to the definition of the Bulk Electric System as approved by Federal Energy Regulation Committee ("FERC"). These incremental costs were above the respective rate allowance during the twelve months ended June 30, 2015 and represent the amount Central Hudson deferred on its books based on actual costs incurred. The incremental amount Central Hudson has deferred on its books as of December 31, 2015 is $1.1 million, including carrying charges. The Company believes the incremental costs associated with these new compliance requirements meet the PSC's criteria for deferral: 1) amount is incremental to the amount in rates; 2) the incremental amount is material and extraordinary in nature; and 3) the utility's earnings are below the authorized rate of return on common equity.

NOTE 4 – Income Tax

In September of 2010, Central Hudson filed a request with the Internal Revenue Service (“IRS”) to change the company’s tax accounting method related to costs to repair and maintain utility assets. The change was effective for the tax year ended December 31, 2009. This change allows Central Hudson to take a current tax deduction for a significant amount of expenditures that were previously capitalized for tax purposes.

This change resulted in federal and state net operating income tax losses (“NOL”). For Federal tax purposes, CH Energy Group elected to carry back the NOL, which resulted in tax refunds for the tax years 2004 through 2008. The remaining Federal NOL for CH Energy Group was carried forward and the balance fully utilized in 2014. Central Hudson fully utilized its Federal NOL carryforward in 2013. CH Energy Group fully utilized its New York State (“NYS”) NOL carryforward in 2014, and Central Hudson has a NYS NOL carryforward of approximately $3.9 remaining and if unused, will expire at the end of 2030. Management believes future taxable income will more likely than not be sufficient to utilize all of the tax carryforward prior to its expiration. Future tax benefits resulting from this change are included within “Accumulated Deferred Income Tax” on the CH Energy Group Consolidated Balance Sheet and the Central Hudson Balance Sheet.

In September 2012, Central Hudson filed corporate income tax returns for the year ended December 31, 2011. With that filing, Central Hudson included an election to adopt the provisions of Revenue Procedure 2011-43 (“Rev Proc”), which provided IRS guidance related to a repair deduction previously taken on electric transmission and distribution property. As such, tax reserves related to the electric transmission and distribution repair deductions, which were established prior to issuance of the Rev Proc, were reclassified to deferred tax liability accounts.

IRS guidance with respect to repairs taken on Gas Transmission and Distribution repairs is still pending. Therefore, remaining reserves related to the gas repair deduction continue to be shown as “Tax Reserve” under the Deferred Credits and Other Liabilities section of the CH Energy Group and Central Hudson Balance Sheet.

Other than the uncertain tax position related to Central Hudson’s accounting method change for gas transmission and distribution repairs, there are no other uncertain tax positions. Increases to the tax reserve during 2015 and 2014 reflect the ongoing uncertainty related to Gas Transmission and Distribution repair deductions. The additional increase in 2015 of the tax reserve was a result of $0.1 million of NYS uncertain tax position that was previously reclassified to a deferred tax asset per ASU No. 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists.*

The following is a summary of activity related to uncertain tax positions (In Thousands):

	Year Ended December 31, 2015	Year Ended December 31, 2014
Tax reserve balance at the beginning of the period	$ 2,693	$ 2,539
Adjustments related to tax accounting method change	827	154
Tax reserve balance at the end of the period	$ 3,520	$ 2,693

Jurisdiction	Tax Years Open for Audit
Federal	2012 – 2014
New York State	2013 – 2014

Components of Income Tax - CH Energy Group

The following is a summary of the components of federal and state income taxes for CH Energy Group as reported in its Consolidated Statement of Income (In Thousands):

	Year Ended December 31, 2015	2014	2013
Federal income tax	$ 4,692	$ 3,778	$ -
State income tax	3,371	677	521
Deferred federal income tax	18,768	14,951	4,634
Deferred state income tax	4,297	790	2,419
Total income tax from continuing operations	$ 31,128	$ 20,196	$ 7,574

Reconciliation - CH Energy Group

The following is a reconciliation between the amount of federal income tax computed on income before taxes at the statutory rate and the amount reported in CH Energy Group's Consolidated Statement of Income (In Thousands):

	Year Ended December 31, 2015	2014	2013
Net income from Continuing Operations	$ 43,740	$ 26,631	$ 4,734
Federal income tax	4,692	3,778	-
State income tax	3,371	677	521
Deferred federal income tax (1)	18,768	14,951	4,634
Deferred state income tax (1)	4,297	790	2,419
	$ 74,868	$ 46,827	$ 12,308
Computed federal tax at 35% statutory rate	$ 26,204	$ 16,389	$ 4,308
State income tax net of federal tax benefit	3,868	2,504	2,105
State income tax prior period adjustment	(797)	-	-
State income tax rate change	1,913	(1,203)	-
Depreciation flow-through	3,208	4,009	2,968
Cost of Removal	(2,566)	(2,347)	(2,418)
Nondeductible compensation expense	8	1,756	-
Merger Transaction Costs	-	(221)	1,169
Other	(710)	(691)	(558)
Total income tax	$ 31,128	$ 20,196	$ 7,574
Effective tax rate - federal	31.3%	40.0%	37.6%
Effective tax rate - state	10.2%	3.1%	23.9%
Effective tax rate - combined	41.5%	43.1%	61.5%

(1) In 2015, there was a change in presentation of the above chart related to federal and state deferred taxes. The federal benefit of state deferred tax in 2015 is shown on the "Deferred federal income tax" line, whereas in 2014 and 2013, it was shown net within the "Deferred state income tax" line. If the federal and state effective tax rates for 2015 were presented in line with the 2014 and 2013 presentation, the federal and state effective tax rates would have been 33.3% and 8.2%, respectively.

On March 31, 2014, NYS enacted into law a NYS corporate income tax rate reduction from the current 7.1% to 6.5%, effective January 1, 2016. Based on management's estimate that the ending balance in the NYS deferred tax accounts as of January 1, 2016 would be a net liability, the adjustment to reflect the impact of this change in rate resulted in a reduction to 2014 NYS tax expense and a reduction to the state effective tax rate. In 2015, this estimate was updated based on the actual ending NYS deferred tax balances as of December 31, 2015 to which the rate change applied. The adjustment to reduce the future deferred tax benefit of the ending net NYS deferred tax asset balance resulted in an increase to 2015 NYS tax expense and an increase in the state effective tax rate for 2015.

The higher overall effective rate for 2014 is due to the 2014 impact of the nondeductible compensation expense related to the election by two CH Energy Group officers to resign under the Change in Control agreements. The higher than average effective tax rate for year ended December 31, 2013 is due to the impact of nondeductible compensation expense related to the election by two CH Energy Group officers to resign under Change in Control agreements. Net income before tax for the year ended December 31, 2013 includes the impact of the Positive Benefit Adjustment ("PBA") of $35 million and the Community Benefit Fund of $5 million recorded upon the closing of the Fortis transaction. The lower net income resulting from the impact of the PBA and Community Benefit Fund has also resulted in a further distortion of the effective rate for year ended December 31, 2013. In 2015, there was a change in how state deferred taxes were calculated. The federal benefit of state deferred tax is shown on the Federal deferred tax line, whereas in 2014 and 2013, it was shown in the state line.

The following is a summary of the components of deferred taxes as reported in CH Energy Group's Consolidated Balance Sheet (In Thousands):

	December 31,	
	2015	2014
Accumulated Deferred Income Tax Asset:		
Unbilled revenues	$ 7,000	$ 9,749
Plant-related	5,405	8,967
Regulatory liability - future income tax	21,340	24,180
OPEB expense	22,328	41,551
PBA	-	6,459
Rate Moderator	25,063	-
Contributions in aid of construction	11,966	7,925
Directors and officers deferred compensation	6,298	6,317
Revenue Decoupling Mechanism	2,147	-
Other	16,298	33,872
Accumulated Deferred Income Tax Asset	117,845	139,020
Accumulated Deferred Income Tax Liability:		
Depreciation	281,499	254,907
Repair allowance	8,443	8,852
Pension expense	16,005	18,387
Change in tax accounting for repairs	73,195	62,430
Regulatory asset - future income tax	22,885	28,642
PSC assessments	1,411	902
Cost of removal	6,024	5,469
Electric fuel costs	-	7,649
Pension reserve carrying charges	468	6,697
Revenue decoupling mechanism	-	2,222
Gas costs	490	3,109
Storm deferrals	2,117	2,024
Other	4,774	11,713
Accumulated Deferred Income Tax Liability	417,311	413,003
Net Deferred Income Tax Liability	$ 299,466	$ 273,982

Components of Income Tax - Central Hudson

The following is a summary of the components of state and federal income taxes for Central Hudson as reported in its Statement of Income (In Thousands):

	Year Ended December 31,		
	2015	2014	2013
Federal income tax	$ 5,998	$ 10,718	$ 1,544
State income tax	2,371	667	1,292
Deferred federal income tax	18,420	9,921	8,259
Deferred state income tax	4,357	1,055	553
Total income tax	$ 31,146	$ 22,361	$ 11,648

Reconciliation - Central Hudson

The following is a reconciliation between the amount of federal income tax computed on income before taxes at the statutory rate and the amount reported in Central Hudson's Statement of Income (In Thousands):

	Year Ended December 31,		
	2015	2014	2013
Net income	$ 45,588	$ 33,844	$ 20,299
Federal income tax	5,998	10,718	1,544
State income tax	2,371	667	1,292
Deferred federal income tax (1)	18,420	9,921	8,259
Deferred state income tax (1)	4,357	1,055	553
Income before taxes	$ 76,734	$ 56,205	$ 31,947
Computed federal tax at 35% statutory rate	$ 26,857	$ 19,672	$ 11,181
State income tax net of federal tax benefit	3,257	2,692	1,393
State income tax prior period adjustment	(797)	-	-
State income tax rate change	1,913	(1,203)	-
Depreciation flow-through	3,208	4,009	2,968
Cost of Removal	(2,566)	(2,347)	(2,418)
Other	(726)	(462)	(1,476)
Total income tax	$ 31,146	$ 22,361	$ 11,648
Effective tax rate - federal	31.8%	36.7%	30.7%
Effective tax rate - state	8.8%	3.1%	5.8%
Effective tax rate - combined	40.6%	39.8%	36.5%

(1) In 2015, there was a change in presentation of the above chart related to federal and state deferred taxes. The federal benefit of state deferred tax in 2015 is shown on the "Deferred federal income tax" line, whereas in 2014 and 2013, it was shown net within the "Deferred state income tax" line. If the federal and state effective tax rates for 2015 were presented in line with the 2014 and 2013 presentation, the federal and state effective tax rates would have been 33.8% and 6.8%, respectively.

On March 31, 2014, NYS enacted into law a NYS corporate income tax rate reduction from the current 7.1% to 6.5%, effective January 1, 2016. Based on management's estimate that the ending balance in the NYS deferred tax accounts as of January 1, 2016 would be a net liability, the adjustment to reflect the impact of this change in rate resulted in a reduction to 2014 NYS tax expense and a reduction to the state effective tax rate. In 2015, this estimate was updated based on the actual ending NYS deferred tax balances as of December 31, 2015 to which the rate change applied. The adjustment to reduce the future deferred tax benefit of the ending net NYS deferred tax asset balance resulted in an increase to 2015 NYS tax expense and an increase in the state effective tax rate for 2015. Net income before tax for the year ended December 31, 2013 includes the impact of the Positive Benefit Adjustment ("PBA") of $35 million and the Community Benefit Fund of $5 million recorded upon the closing of the Fortis transaction. The lower net income resulting from the impact of the PBA and Community Benefit Fund has also resulted in a further distortion of the effective rate for year ended December 31, 2013.

The following is a summary of the components of deferred taxes as reported in Central Hudson's Balance Sheet (In Thousands):

	December 31, 2015	December 31, 2014
Accumulated Deferred Income Tax Asset:		
Unbilled revenues	$ 7,000	$ 9,749
Plant-related	5,405	8,967
OPEB expense	22,328	41,551
NOL carryforwards[(1)]	-	541
PBA	-	6,459
Rate Moderator	25,063	
Contributions in aid of construction	11,966	7,925
Regulatory liability - future income tax	21,340	24,180
Directors and officers deferred compensation	6,298	6,317
Revenue Decoupling Mechanism	2,147	
Other	13,476	25,126
Accumulated Deferred Income Tax Asset	115,023	130,815
Accumulated Deferred Income Tax Liability:		
Depreciation	281,499	254,907
Repair allowance	8,443	8,852
Pension expense	16,005	18,387
Change in tax accounting for repairs	73,195	62,430
Regulatory asset - future income tax	22,885	28,642
PSC assessments	1,411	902
Cost of removal	6,024	5,469
Electric fuel costs	-	7,649
Pension reserve carrying charges	468	6,697
Revenue decoupling mechanism	-	2,222
Gas costs	490	3,109
Storm deferrals	2,117	2,024
Other	4,774	11,713
Accumulated Deferred Income Tax Liability	417,311	413,003
Net Deferred Income Tax Liability	$ 302,288	$ 282,188

(1) Under ASU No. 2013-11, the presentation of uncertain tax positions when a NOL carryforward exists should be netted with the NOL carryforward. As of December 31, 2015 and December 31, 2014, approximately $0.2 million and $0.3 million respectively of uncertain tax positions have been netted with the NOL carryforward presented above.

NOTE 5 – Acquisitions, Investments and Divestitures

Acquisitions

During the twelve months ended December 31, 2015 and 2014, there were no acquisitions made by CH Energy Group or any of its subsidiaries.

Divestitures

During the first quarter of 2014, CHEC divested Griffith. The results of operations of Griffith are presented in discontinued operations in the twelve months ended December 31, 2014 and 2013 in the CH Energy Group Consolidated Statement of Income. Management has elected to include cash flows from discontinued operations of these investments with those from continuing operations in the CH Energy Group Consolidated Statement of Cash Flows. The details of the sale transaction are as follows (In Thousands):

		Griffith
Date of Sale		3/4/2014
Assets:		
Cash	$	4,151
Accounts Receivable, net of allowance		47,170
Fuel, Materials and Supplies		5,228
Other Current Assets		6,656
Total Current Assets		63,205
Net Intangibles		48,660
Other Assets		1,227
Property, Plant and Equipment:		
Property, plant and equipment		34,711
Less: Accumulated depreciation		24,235
Total property, plant and equipment, net		10,476
Assets sold	$	123,568
Liabilities:		
Accounts Payable	$	10,933
Deferred Revenue		4,448
Accrued Expenses		2,325
Accrued Vacation and Payroll		2,027
Other Current Liabilities		6,765
Total Current Liabilities		26,498
Other Liabilities		4,898
Liabilities sold	$	31,396
Net Assets Sold	$	92,172
Net Proceeds from Sale	$	100,208
Pre-tax gain on sales transaction	$	8,036
Net Increase to Earnings	$	3,153

The table below provides additional detail of the financial results of the discontinued operations (In Thousands):

	Year Ended December 31, 2015	2014	2013
Revenues from discontinued operations	$ -	$ 85,856	$ 298,367
Income from discontinued operations before tax	-	6,908	7,540
Gain from sale of discontinued operations	-	8,036	-
Income tax expense from discontinued operations	-	7,255	3,092

Investments

The value of CHEC's investments as of December 31, 2015 and 2014 are as follows (In Thousands):

		Equity Investment	
CHEC Investment	Description	December 31, 2015	December 31, 2014
CH-Community Wind	50% equity interest in a joint venture that owns 18% interest in two operating wind projects	-	-
Other	Partnerships and an energy sector venture capital fund	1,078	1,653
		$ 1,078	$ 1,653

CHEC's remaining investments are not considered a part of the core business; however, management intends to retain these investments at this time.

In 2014, CH Energy Group formed CHET to engage in transmission projects. The first undertaking of CHET was the execution of the Transco agreement. CHET ownership interest in Transco is 6.1%. As of December 31, 2015 and 2014, the value of CHET's investment in Transco was $0.3 million and $0.1 million, respectively.

NOTE 6 – Research and Development

Central Hudson's R&D expenditures were $4.0 million in 2015, $3.3 million in 2014 and $3.6 million in 2013. These expenditures were for internal research programs and for contributions to research administered by New York State Energy Research and Development Authority ("NYSERDA"), the Electric Power Research Institute and other industry organizations.

NOTE 7 – Short-Term Borrowing Arrangements

Description	CH Energy Group	Central Hudson
Revolving Credit Facilities:(1)		
Limit	$50 million(2) / $200 million(3)	$200 million(3)
Expiration	July 10, 2020 / October 15, 2020	October 15, 2020

	CH Energy Group December 31,		Central Hudson December 31,	
	2015	2014	2015	2014
Outstanding (In Thousands):				
Committed Credit	$ 12,000	$ -	$ 12,000	$ -
Uncommitted Credit(4)	13,000	-	13,000	-
Intercompany Borrowing(5)	-	-	2,000	-
Total	$ 25,000	$ -	$ 27,000	$ -
Weighted Average Interest Rate	1.16%	0%	1.15%	0%

(1) Providing committed credit.

(2) Participating banks in the credit facility for CH Energy Group are JPMorgan Chase Bank, N.A., Bank of America, N.A., Wells Fargo Bank, N.A. and KeyBank National Association. If these lenders are unable to fulfill their commitments under these facilities, funding may not be available as needed.

(3) Participating banks in the credit facility for Central Hudson are JPMorgan Chase Bank, N.A., Bank of America, N.A., Wells Fargo Bank, N.A., KeyBank National Association, Bank of Nova Scotia, N.A. and Citizens Bank, N.A. If these lenders are unable to fulfill their commitments under these facilities, funding may not be available as needed.

(4) To diversify cash sources and provide competitive options to minimize Central Hudson's cost of short-term debt.

(5) Central Hudson uncommitted credit outstanding at December 31, 2015 included $2 million of intercompany debt from CH Energy Group.

NOTE 8 – Capitalization – Common and Preferred Stock

For a schedule of activity related to common stock, paid-in capital, and capital stock, see the Consolidated Statements of Equity for CH Energy Group and Central Hudson.

On June 26, 2013, immediately prior to the completion of the Fortis acquisition and pursuant to the Order Authorizing Acquisition Subject to Conditions, Central Hudson issued one share of a new class of Limited Voting Junior Preferred Stock, $100 par value per share (“Junior Preferred Stock”), with no dividend rights. The share has a voting right solely with respect to whether Central Hudson may file a voluntary bankruptcy petition, a petition for receivership or institute any other liquidation or similar proceeding.

On June 27, 2013, at the effective time of the closing of the Fortis acquisition, all shares of CH Energy Group Common Stock that immediately prior to the effective time were issued and outstanding or held in treasury, were cancelled and ceased to exist. Subsequently, 14,961,400 shares of new common stock, $0.01 par value per share, were issued to FortisUS, Inc. (“FortisUS”) which became the sole shareholder of CH Energy Group. Following the closing of the transaction, FortisUS purchased an additional one million shares of the new common stock of CH Energy Group for $65.0 million.

Other than the one share of a new class of Junior Preferred Stock mentioned above, Central Hudson has no outstanding preferred stock as of December 31, 2015.

On July 27, 2015, CH Energy Group received a capital infusion in the amount of $10 million from FortisUS. The contribution was recorded as paid in capital, see CH Energy Group Consolidated Statement of Equity.

Common Stock Dividends

CH Energy Group's ability to pay dividends is affected by the ability of its subsidiaries to pay dividends. The Federal Power Act limits the payment of annual dividends by Central Hudson to its retained earnings. More restrictive is the PSC's limit on the dividends Central Hudson may pay to CH Energy Group, which is 100% of the average annual income available for common stock, calculated on a two-year rolling average basis. Based on this calculation, Central Hudson is currently restricted to a maximum annual payment of $39.7 million in dividends to CH Energy Group. Central Hudson's ability to pay dividends would be reduced to 75% of its average annual income in the event of a downgrade of its senior debt rating below "BBB+" by more than one rating agency if the stated reason for the downgrade is related to any of CH Energy Group's or Central Hudson's affiliates. Further restrictions are imposed for each downgrade below this level. In addition, Central Hudson would not be allowed to pay dividends if its average common equity ratio for the 13 months prior to a proposed dividend was more than 200 basis points below the ratio used in setting rates (currently 48%).

In 2015, the Board of Directors of CH Energy Group declared and paid dividends of $22 million to FortisUS, the sole shareholder of CH Energy Group. In 2014 the Board of Directors of CH Energy Group declared and paid dividends of $75 million to FortisUS. On January 15, 2016, the Board of Directors of CH Energy Group declared dividends of $5.5 million, payable to FortisUS. The dividends were paid on January 28, 2016. CH Energy Group's other subsidiaries do not have expressed restrictions on their ability to pay dividends.

In 2015, the Board of Directors of Central Hudson declared and paid dividends of approximately $24.5 million to parent CH Energy Group. In 2014, Central Hudson paid $5 million of dividends to CH Energy Group. No dividends were declared or paid to parent company CH Energy Group during January 2016.

NOTE 9 – Capitalization - Long-Term Debt

Details of CH Energy Group's and Central Hudson's long-term debt are as follows (In Thousands):

		December 31, 2015		December 31, 2014	
Series	Maturity Date	Principal	Unamortized Debt Issuance Costs	Principal	Unamortized Debt Issuance Costs
Central Hudson:					
Promissory Notes:					
2007 Series F (6.028%)[5]	Sep. 01, 2017	33,000	68	33,000	109
2004 Series E (5.05%)[4]	Nov. 04, 2019	27,000	80	27,000	102
2006 Series E (5.76%)[4]	Nov. 17, 2031	27,000	275	27,000	293
1999 Series B[1],[2]	Jul. 01, 2034	33,700	320	33,700	337
2005 Series E (5.84%)[4]	Dec. 05, 2035	24,000	198	24,000	208
2007 Series F (5.804%)[5]	Mar. 23, 2037	33,000	294	33,000	308
2009 Series F (5.80%)[5]	Nov. 01, 2039	24,000	259	24,000	270
2010 Series A (4.30%)[6]	Sep. 21, 2020	16,000	47	16,000	57
2010 Series B (5.64%)[6]	Sep. 21, 2040	24,000	124	24,000	129
2010 Series G (2.756%)[6]	Apr. 01, 2016	8,000	4	8,000	20
2010 Series G (4.15%)[6]	Apr. 01, 2021	44,150	239	44,150	284
2010 Series G (5.716%)[6]	Apr. 01, 2041	30,000	261	30,000	271
2011 Series G (3.378%)[6]	Apr. 01, 2022	23,400	184	23,400	213
2011 Series G (4.707%)[6]	Apr. 01, 2042	10,000	114	10,000	118
2012 Series G (4.776%)[6]	Apr. 01, 2042	48,000	556	48,000	577
2012 Series G (4.065%)[6]	Oct. 01, 2042	24,000	334	24,000	346
2013 Series C (2.45%)[7]	Nov. 1, 2018	30,000	86	30,000	116
2013 Series D (4.09%)[7]	Dec. 2, 2028	16,700	135	16,700	146
2014 Series E [7],[8]	Mar. 30, 2024	30,000	171	30,000	192
2015 Series F (2.98%)[7]	Mar. 31, 2025	20,000	145	-	-
		525,950	3,894	505,950	4,096
Less: Current Portion		(8,000)	-	-	-
Central Hudson Net Long-term Debt		$ 517,950	$ 3,894	$ 505,950	$ 4,096
CH Energy Group:					
Promissory Notes:					
2009 Series B (6.80%)	Dec. 15, 2025	18,095	-	19,325	-
Less: Current Portion		(1,315)	-	(1,230)	-
CH Energy Group Net Long-term Debt		$ 534,730	$ 3,894	$ 524,045	$ 4,096

(1) Promissory Notes issued in connection with the sale by NYSERDA of tax-exempt pollution control revenue bonds.
(2) Variable (auction) rate notes.
(3) Issued pursuant to a 2001 PSC Order approving the issuance by Central Hudson prior to June 30, 2004, of up to $100 million of unsecured medium-term notes.
(4) Issued pursuant to a 2004 PSC Order approving the issuance by Central Hudson prior to December 31, 2006, of up to $85 million of unsecured medium-term notes.
(5) Issued pursuant to a 2006 PSC Order approving the issuance by Central Hudson prior to December 31, 2009, of up to $120 million of unsecured medium-term notes.
(6) Issued pursuant to a 2009 PSC Order approving the issuance by Central Hudson prior to December 31, 2012, of up to $250 million of unsecured medium-term notes or other forms of long-term indebtedness.
(7) Issued pursuant to a 2012 PSC Order approving the issuance by Central Hudson prior to December 31, 2015, of up to $250 million of unsecured medium-term notes or other forms of long-term indebtedness.
(8) Variable rate notes

In March 2015, Central Hudson issued $20 million of 10-year Series F notes with an interest rate of 2.98% per annum.

At December 31, 2015, Central Hudson has $30 million of 10-year Series E notes with a floating interest rate of 3 month LIBOR plus 1%. To mitigate the potential cash flow impact from unexpected increases in short-term interest rates, Central Hudson purchased a 3-year interest rate cap that will expire on March 26, 2017. The rate cap has a notional amount equal to the outstanding principal amount of the 2014 Series E notes and is based on the quarterly reset of the LIBOR rate on the quarterly interest payment dates. Central Hudson would receive a payout if the LIBOR rate exceeds 4% at the start of any quarterly interest period during the term of the cap. There were no payouts received during the year ended December 31, 2015.

The principal amount of Central Hudson's outstanding 1999 Series B NYSERDA Bonds totaled $33.7 million at December 31, 2015. These are tax-exempt multi-modal bonds that are currently in a variable rate mode. To mitigate the potential cash flow impact from unexpected increases in short-term interest rates on Series B NYSERDA Bonds, on March 27, 2014, Central Hudson purchased an interest rate cap. The rate cap has a notional amount equal to the outstanding principal amount of the Series B bonds and expires on April 1, 2016. The cap is based on the monthly weighted average of an index of tax-exempt variable rate debt, multiplied by 175%. Central Hudson would receive a payout if the adjusted index exceeds 5.0% for a given month. There were no payouts received during the year ended December 31, 2015.

In its orders, the PSC has authorized the continued deferral accounting treatment for variations in the interest costs of the 1999 Series B NYSERDA Bonds and the Series E 10-year notes. As such, variations between the actual interest rates on these bonds and the interest rate included in the current delivery rate structure for these bonds are deferred for future recovery from or refund to customers and therefore do not impact earnings.

See Note 14 – "Accounting for Derivative Instruments and Hedging Activities" for fair value disclosures related to this instrument.

Long-Term Debt Maturities

See Note 15 – "Fair Value Measurements" for a schedule of long-term debt maturing or to be redeemed during the next five years and thereafter.

Financing Petition

On April 30, 2015, Central Hudson filed a petition with the PSC (Case 15-M-0251) seeking approval to: (a) enter into multi-year committed credit agreements to provide committed funding to meet expected liquidity needs in amounts not to exceed $200 million in the aggregate and with maturities not to exceed five years and (b) issue and sell long-term debt from time to time through December 31, 2018, in an amount not to exceed $350 million in the aggregate.

A higher level of committed credit will provide greater liquidity to support construction forecasts, known seasonality, volatile energy markets, adverse borrowing environments, and other unforeseen events. The approval to issue and sell $350 million of long-term debt will support Central Hudson's financing of its construction expenditures, refund maturing long-term debt, potentially refinance $33.7 million of multi-modal long-term NYSERDA bonds and refinance up to $30 million of other securities if economic and appropriate.

On September 18, 2015, the PSC issued its Order Authorizing Issuance of Securities for Central Hudson in this proceeding. The Order grants the authorization requested for $200 million of committed credit; grants the authorization requested, with conditions, for $350 million of long-term debt; and revokes the authorization granted in the prior financing order, avoiding the overlap in orders (the prior financing order covered a period ending December 31, 2015 and the new order is effectively immediately).

Debt Covenants

CH Energy Group's $18.1 million of privately placed notes require compliance with certain covenants including maintaining a ratio of total consolidated debt to total consolidated capitalization of no more than 0.65 to 1.00 and not permitting certain debt, other than the privately placed notes, associated with the unregulated operations of CH Energy Group to exceed 10% of total consolidated assets. Currently, CH Energy Group is in compliance with all of these debt covenants.

NOTE 10 – Post-Employment Benefits

Pension Benefits

Central Hudson has a non-contributory Retirement Income Plan ("Retirement Plan") covering substantially all of its employees hired before January 1, 2008. The Retirement Plan is a defined benefit plan, which provides pension benefits based on an employee's compensation and years of service. In 2007, Central Hudson amended the Retirement Plan to eliminate these benefits for managerial, professional, and supervisory employees hired on or after January 1, 2008. The Retirement Plan for unionized employees was similarly amended for all employees hired on or after May 1, 2008. As of December 31, 2015, 43% of all active employees were not eligible to participate in the Retirement Plan. The Retirement Plan's assets are held in a trust fund ("Trust Fund"). Central Hudson has provided periodic updates to the benefit formulas stated in the Retirement Plan.

Decisions to fund Central Hudson's Retirement Plan are based on several factors, including, but not limited to, corporate resources, projected investment returns, actual investment returns, inflation, the value of plan assets relative to plan liabilities, regulatory considerations, interest rate assumptions and the Pension Protection Act of 2006 ("PPA"). Based on the funding requirements of the PPA, Central Hudson plans to make contributions that maintain the target funded percentage at 80% or higher. Contributions to the Retirement Plan during the years ended December 31, 2015 and 2014 were $21.3 million and $16.4 million, respectively.

Overall, Central Hudson's unfunded liability decreased by approximately $8.9 million, resulting from a decrease in plan liabilities of $27.6 million coupled with a $18.7 million decrease in plan assets. The increase in the plan's discount rate was a primary factor contributing to the decrease to the plan liability. The decrease in plan assets was primarily driven by market volatility experienced in 2015. Central Hudson is not planning on making any contributions in 2016 due to the higher than expected 2015 contributions. As noted above, actual contributions could vary significantly based upon a range of factors that Central Hudson considers in its funding decisions.

The balance of Central Hudson's accrued pension costs (i.e., the under-funded status) is as follows (In Thousands):

	December 31, 2015[(1)]	December 31, 2014[(1)]
Accrued pension costs	$ 60,651	$ 69,593

(1) Includes approximately $232K at December 31, 2015 and $555K of accrued pension liability at December 31, 2014 recorded at CH Energy Group as a result of the resignation in 2014 of two CH Energy Group officers with change in control agreements.

These balances include the difference between the projected benefit obligation ("PBO") for pensions and the market value of the pension assets, and any liability for the non-qualified SERP.

The following reflects the impact of the recording of funding status adjustments on the Balance Sheets of CH Energy Group and Central Hudson (In Thousands):

	December 31, 2015[1]	December 31, 2014[1]
Prefunded pension costs prior to funding status adjustment	$ 30,510	$ 29,317
Additional liability required	(91,161)	(98,910)
Total accrued pension costs	$ (60,651)	$ (69,593)
Total offset to additional liability - Regulatory assets - Pension Plan	$ 91,161	$ 98,910

[1] Includes approximately $232K at December 31, 2015 and $555K of accrued pension liability at December 31, 2014 recorded at CH Energy Group only as a result of the resignation in 2014 of two CH Energy Group officers with change in control agreements.

Gains or losses and prior service costs or credits that arise during the period, but that are not recognized as components of net periodic pension cost would typically be recognized as a component of other comprehensive income, net of tax. However, Central Hudson has PSC approval to record regulatory assets rather than adjusting comprehensive income to offset the additional liability.

The valuation of the current and prior year PBO was determined at December 31, 2015 and 2014, using discount rates of 4.20% and 3.90% respectively, as determined from the Mercer Pension Discount Yield Curve reflecting projected pension cash flows. A 1.00% increase in the discount rate would affect the projection of the pension PBO by approximately $76.4 million. Central Hudson accounts for pension activity in accordance with PSC-prescribed provisions, which among other things, requires a ten-year amortization of actuarial gains and losses.

The 2015 Rate Order includes rate allowances for pension and OPEB expense which more closely approximates the recent cost of providing these benefits. Authorization remains in effect for the deferral of any differences between rate allowances and actual costs under the 1993 PSC Policy to counteract the volatility of these costs. The 2015 Rate Order again authorized Central Hudson to offset a significant portion of deferred balances for pension and OPEB expense for the electric department with available deferred credit balances due to customers.

Retirement Plan Estimates of Long-Term Rates of Return

The expected long-term rate of return on the Retirement Plan assets utilized in the calculation of the net periodic benefit cost for 2015 is 6.10%, net of investment expense. In determining the expected long-term rate of return on plan assets, Central Hudson considered forward-looking estimated returns evaluated in light of current economic conditions and based on internally consistent economic models. The expected long-term rate of return is a weighted average based on each plan's investment mix and the forward-looking estimated returns for each investment class. Central Hudson monitors actual performance against target asset allocations and adjusts actual allocations and targets in accordance with the Retirement Plan strategy. A 100 basis point decrease in the expected long-term rate of return would have increased the 2015 net periodic benefit cost by $5.9 million.

Retirement Plan Policy and Strategy

Central Hudson's Retirement Plan investment policy seeks to achieve long-term growth and income to match the long-term nature of its funding obligations. The investment policy also seeks to reduce the volatility of the plan's funded status and the level of contributions by more closely aligning the characteristics of plan assets with liabilities. Due to market value fluctuations, Retirement Plan assets require rebalancing from time to time to maintain the asset allocation within target ranges. Central Hudson cannot guarantee that the Retirement Plan's return objectives or funded status objectives will be achieved.

Asset allocation targets in effect for the twelve months ended December 31, 2015 as well as actual asset allocations as of December 31, 2015 and December 31, 2014 expressed as a percentage of the market value of Retirement Plan assets, are summarized in the table below:

Asset Class	December 31, 2015	Minimum	Target Average	Maximum	December 31, 2014
Equity Securities	49.9%	41%	50%	59%	49.5%
Debt Securities	47.7%	45%	50%	55%	48.5%
Other[1]	2.4%	-%	-%	10%	2.0%

[1] Consists of temporary cash investments, as well as receivables for investments sold and interest, and payables for investments purchased, which have not settled as of that date.

Retirement Plan Investment Valuation

The Retirement Plan assets are valued under the current fair value framework. See Note 14 – "Accounting for Derivative Instruments and Hedging Activities" for further discussion regarding the definition and levels of fair value hierarchy established by accounting guidance.

The inputs or methodology used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of December 31, 2015 and 2014, as well as the associated level within the fair value hierarchy in which the fair value measurements in their entirety fall (Dollars in Thousands):

Investment Type	Market Value at 12/31/15	% of Total	Market Value at 12/31/14	% of Total
Level 1:				
Cash	$ -	-%	$ 2,798	0.5%
Level 2:				
Investment Funds - Equities[1]	291,647	49.9	298,424	49.5
Investment Funds - Fixed Income[1]	278,471	47.7	292,235	48.4
Cash Equivalents[2]	12,265	2.1	7,229	1.2
Other Investments	1,780	0.3	2,183	0.4
	$ 584,163	100.0%	$ 602,869	100.0%

(1) Reported at net asset value, which equals redemption price on that date.

(2) Reported at stated value, which approximates fair value on that date.

Other Post-Retirement Benefits

Central Hudson provides certain health care and life insurance benefits for certain retired employees through its post-retirement benefit plans. Substantially all of Central Hudson's unionized employees and managerial, professional and supervisory employees ("non-union") hired prior to January 1, 2008, may become eligible for these benefits if they reach retirement age while employed by Central Hudson. Central Hudson amended its OPEB programs for existing non-union and certain retired employees effective January 1, 2008. Benefit plans for non-union active employees were similarly amended in 2008 which eliminated post-retirement benefits for non-union employees hired on or after January 1, 2008. Plans were also amended to eliminate post-retirement benefits for union employees hired on or after May 1, 2008. Benefits for retirees and active employees are provided through insurance companies whose premiums are based on the benefits paid during the year.

The significant assumptions used to account for these benefits are the discount rate, the expected long-term rate of return on plan assets and the health care cost trend rate. Central Hudson currently selects the discount rate using the Mercer Pension Discount Yield Curve reflecting projected cash flows. The estimates of long-term rates of return and the investment policy and strategy for these plan assets are similar to those used for pension benefits previously discussed in this Note. The estimates of health care cost trend rates are based on a review of actual recent trends and projected future trends.

Central Hudson fully recovers its net periodic post-retirement benefit costs in accordance with the 1993 PSC Policy. Under these guidelines, the difference between the amounts of post-retirement benefits recoverable in rates and the amounts of post-retirement benefits determined by an actuarial consultant in accordance with current accounting guidance related to other post-employment benefits is deferred as either a regulatory asset or a regulatory liability, as appropriate.

Central Hudson's liability (i.e. the under-funded status) for OPEB at December 31, 2015 and 2014, was $19.0 million and $24.8 million, respectively. The cumulative amount of net periodic benefit cost in excess of employer contributions at December 31, 2015 and December 31, 2014 was $43.4 million and $51.5 million, respectively. The difference between these amounts, $24.5 million at December 31, 2015 and $26.7 million at December 31, 2014, will be recognized in Central Hudson's future expense and have been recorded as a regulatory asset in accordance with the 1993 PSC Policy.

Central Hudson sponsors a 401(k) retirement plan ("401(k) plan") for its employees. The 401(k) plan provides for employee tax-deferred salary deductions for participating employees and employer matches. The matching benefit varies by employee group. The costs of Central Hudson's matching contributions were $3.2 million for 2015, $2.5 million for 2014 and $2.3 million for 2013. Central Hudson also provides an additional contribution of 3% to the 401(k) plan of annualized base salary for eligible employees who do not qualify for Central Hudson's Retirement Income Plan.

OPEB Estimates of Long-Term Rates of Return

The expected long-term rate of return on OPEB assets utilized in the calculation of the net periodic benefit cost for 2015 was 6.94%, net of investment expense. In determining the expected long-term rate of return on plan assets, Central Hudson considered forward-looking estimated returns for each asset class evaluated in light of current economic conditions. The expected long-term rate of return is a weighted average based on each plan's investment mix and the forward-looking estimated returns for each investment class. A 100 basis point decrease in the expected long-term rate of return would have increased the 2015 net periodic benefit cost by $1.2 million. Central Hudson monitors actual performance against target asset allocations and adjusts actual allocations and targets as deemed appropriate in accordance with the OPEB Plan's strategy.

OPEB Policy and Strategy

Central Hudson currently funds its union OPEB obligations through a voluntary employee's beneficiary association ("VEBA"), and funds its management OPEB liabilities through a 401(h) plan. The VEBA and 401(h) plan are both a form of trust fund. Central Hudson's VEBA investment policy seeks to achieve a rate of return for the VEBA over the long term that contributes to meeting the VEBA's current and future obligations, including interest and benefit payment obligations. The policy also seeks to earn long-term returns from capital appreciation and current income that at least keep pace with inflation over the long term. Central Hudson's 401(h) plan is invested with the previously mentioned Retirement Plan's investments. However, there are no assurances that the OPEB Plan's return objectives will be achieved.

The asset allocation strategy employed in the VEBA reflects Central Hudson's return objectives and what management believes is an acceptable level of short-term volatility in the market value of the VEBA's assets in exchange for potentially higher long-term returns. The mix of assets shall be broadly diversified by asset class and investment styles within asset classes, based on the following asset allocation targets, expressed as a percentage of the market value of the VEBA's assets, summarized in the table below:

Asset Class	December 31, 2015	Minimum	Target Average	Maximum	December 31, 2014
Equity Securities	64.9%	55%	65%	75%	64.9%
Debt Securities	34.9%	25%	35%	45%	34.8%
Other	0.2%	- %	- %	- %	0.3%

Due to market value fluctuations, the OPEB Plan assets require periodic rebalancing from time to time to maintain the asset allocation within target ranges.

Management uses outside consultants and outside investment managers to aid in the determination of the OPEB Plan's asset allocation and to provide the management of actual plan assets, respectively.

OPEB Investment Valuation

The OPEB Plan assets are valued under the current fair value framework. See Note 14 – "Accounting for Derivative and Hedging Activities" for further discussion regarding the definition and levels of fair value hierarchy established by guidance.

The inputs or methodology used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of December 31, 2015 and 2014, as well as the associated level within the fair value hierarchy in which the fair value measurements in their entirety fall.

401 (h) Plan Assets
(Dollars in Thousands)

Investment Type	Market Value at 12/31/15	% of Total	Market Value at 12/31/14	% of Total
Level 1:				
Cash	$ -	-%	$ 97	0.5%
Level 2:				
Investment Funds - Equities[1]	10,257	49.8	10,372	49.5
Investment Funds - Fixed Income[1]	9,794	47.6	10,156	48.4
Cash Equivalents[2]	431	2.1	251	1.2
Other Investments	96	0.5	76	0.4
	$ 20,578	100.0%	$ 20,952	100.0%

(1) Reported at net asset value, which equals redemption price on that date.
(2) Reported at stated value, which approximates fair value on that date.

Union VEBA Plan Assets
(Dollars In Thousands)

Investment Type	Market Value at 12/31/15	% of Total	Market Value at 12/31/14	% of Total
Level 1:				
Investment Funds - Money Market Mutual Fund	$ 245	0.2%	$ 265	0.3%
Investment Funds - Fixed Income Mutual Funds	20,022	20.7	20,056	20.1
Investment Funds - Equity Securities Mutual Funds	43,426	44.9	44,692	44.9
Level 2:[1]				
Fixed Income Commingled Fund	13,717	14.2	14,597	14.7
Investment Funds - Equity Securities Commingled Fund	19,339	20.0	19,955	20.0
	$ 96,749	100.0%	$ 99,565	100.0%

(1) The Level 2 funds do not have market data available; however, the underlying securities held by those funds do have published market data available.

Reconciliations of Central Hudson's pension and other post-retirement plans' benefit obligations, plan assets, and funded status, as well as the components of net periodic pension cost and the weighted average assumptions are reported on the following chart (Dollars In Thousands):

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 672,462	$ 566,299	$ 145,353	$ 131,938
Service cost	12,808	10,720	2,312	2,098
Interest cost	26,020	25,764	5,425	5,671
Participant contributions	-	-	718	778
Special Termination Benefits	-	555	-	-
Benefits paid	(30,380)	(31,557)	(5,714)	(6,026)
Actuarial (gain)/loss	(36,096)	100,681	(11,773)	10,894
Benefit Obligation at End of Plan Year	$ 644,814	$ 672,462	$ 136,321	$ 145,353
Change in Plan Assets:				
Fair Value of plan assets at beginning of year	$ 602,869	$ 548,216	$ 120,517	$ 113,902
Actual return on plan assets	(8,998)	70,872	365	9,709
Employer contributions	22,387	16,986	1,536	2,238
Participant contributions	-	-	718	778
Benefits paid	(30,380)	(31,557)	(5,714)	(6,026)
Administrative expenses	(1,715)	(1,648)	(96)	(84)
Fair Value of Plan Assets at End of Plan Year	$ 584,163	$ 602,869	$ 117,326	$ 120,517
Reconciliation of Funded Status:				
Funded Status at end of year	$ (60,651)	$ (69,593)	$ (18,995)	$ (24,836)
Amounts Recognized on Balance Sheet:				
Current liabilities	$ (1,081)	$ (1,086)	$ -	$ -
Noncurrent liabilities	(59,570)	(68,507)	(18,995)	(24,836)
Net amount recognized on Balance Sheet	(60,651)	(69,593)	(18,995)	(24,836)
Regulatory asset:				
Net (gain)/loss	84,011	90,144	(8,101)	(4,617)
Prior service costs (credit)	7,148	8,766	(16,352)	(22,084)
Components of Net Periodic Benefit Cost:				
Service cost	$ 12,808	$ 10,720	$ 2,312	$ 2,098
Interest cost	26,020	25,764	5,425	5,671
Special Termination Benefits	-	555	-	-
Expected return on plan assets	(35,474)	(34,818)	(8,164)	(7,953)
Amortization of prior service cost (credit)	1,618	1,618	(5,732)	(5,836)
Amortization of actuarial net loss (gain)	16,223	10,141	(437)	(463)
Net Periodic Benefit Cost	$ 21,195	$ 13,980	$ (6,596)	$ (6,483)

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
Other Changes in Plan Assets and Benefit Obligation Recognized in Regulatory Assets:				
Net (gain)/loss	$ 10,091	$ 66,276	$ (3,921)	$ 9,285
Amortization of actuarial net (loss) gain	(16,223)	(10,141)	437	463
Amortization of prior service (cost) credit	(1,618)	(1,618)	5,732	5,836
Total recognized in regulatory asset	$ (7,750)	$ 54,517	$ 2,248	$ 15,584
Total recognized in net periodic benefit cost and regulatory asset	$ 13,445	$ 68,497	$ (4,348)	$ 9,101
Weighted-average assumptions used to determine benefit obligations:				
Discount rate	4.20%	3.90%	4.20%	3.90%
Rate of compensation increase (average)	4.00%	4.00%	4.00%	4.00%
Measurement date	12/31/15	12/31/14	12/31/15	12/31/14
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31:				
Discount rate	3.90%	4.60%	3.90%	4.60%
Expected long-term rate of return on plan assets	6.10%	6.50%	6.94%	7.09%
Rate of compensation increase (average)	4.00%	4.00%	4.00%	4.00%
Assumed health care cost trend rates at December 31:				
Health care cost trend rate assumed for next year	N/A	N/A	7.07%	7.33%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	N/A	N/A	2038	2029
Pension plans with accumulated benefit obligations in excess of plan assets:				
Projected benefit obligation	$ 644,814	$ 672,462	N/A	N/A
Accumulated benefit obligation	$ 596,116	$ 618,196	N/A	N/A
Fair Value of plan assets	$ 584,163	$ 602,869	N/A	N/A

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year are $17.6 million and $1.5 million, respectively. The estimated net loss and prior service credit for the other defined benefit post-retirement plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year is $1.0 million and $4.9 million, respectively. The amount of transitional obligation to be amortized from regulatory assets is immaterial.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A 1% change in assumed health care cost trend rates would have the following effects (In Thousands):

	One Percentage Point	
	Increase	Decrease
Effect on total of service and interest cost components for 2015	$ 308	$ (268)
Effect on year-end 2015 post-retirement benefit obligation	$ 3,607	$ (3,235)

For 2015, the PBO for Central Hudson's obligation for OPEB costs was determined using a 4.20% discount rate. This rate was determined using the Mercer Pension Discount Yield

Curve reflecting projected cash flows. A 1.00% increase in the discount rate would have decreased the projection of the OPEB obligation by approximately $16.0 million.

Central Hudson's contributions for OPEB totaled $1.5 million and $2.2 million during the years ended December 31, 2015 and 2014. Contribution levels are determined by various factors including the discount rate, expected return on plan assets, medical claims assumptions used, mortality assumptions used, benefit changes, corporate resources and regulatory considerations. In January 2016, Central Hudson made a $1.6 million contribution for OPEB.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service as appropriate, are expected to be paid (In Thousands):

Year	Pension Benefits - Gross	Other Benefits - Gross	Other Benefits - Net(1)
2016	$ 32,930	$ 6,941	$ 6,279
2017	33,243	7,256	6,567
2018	33,549	7,557	6,842
2019	34,226	7,857	7,112
2020	35,221	8,268	7,499
2021 - 2025	191,731	46,406	43,927

(1) Estimated benefit payments reduced by estimated gross amount of Medicare Act of 2003 subsidy receipts expected.

NOTE 11 – Equity-Based Compensation

Share Unit Plan

In January 2015, 47,386 units were granted to the officers of CH Energy Group and Central Hudson under the 2015 SUP, representing the officers' long-term incentives. Two-thirds of the issued SUP Units are performance based and vest upon achievement of specified performance goals over the three year performance period while the remaining third are time-based and vest at the end of the three year period without regard to performance. Each SUP Unit has an underlying value equivalent to the value of one common share of Fortis and is subject to a three-year vesting period, at which time a cash payment may be made, as determined by the Governance and Human Resource Committee of the Board of Directors. The foreign exchange rate utilized for cash payout in the US dollar equivalent corresponds to the exchange rate as of the date of the SUP Unit grant. Each SUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares.

In January 2014, 78,536 units were granted to the officers of CH Energy Group and Central Hudson under the 2014 SUP, representing the officers' long-term incentives. Half of the issued SUP Units are performance based and vest upon achievement of specified performance goals over the three year performance period while the remaining half are time-based and vest at the end of the three year period without regard to performance. Each SUP Unit has an underlying value equivalent to the value of one common share of Fortis and is subject to a three-year vesting period, at which time a cash payment may be made, as determined by the Governance and Human Resource Committee of the Board of Directors. The foreign exchange rate utilized for cash payout in the US dollar equivalent corresponds to the exchange rate as of the date of the SUP Unit payout. Each SUP Unit accrues notional dividend equivalents equal to the dividends declared by the Fortis Board of Directors on Fortis common shares. In the third quarter of 2014, 2,969 SUP Units were forfeited following the resignation of an Officer.

Compensation Expense

The following table summarizes expense for equity-based compensation by award type for the twelve months ended December 31, 2015, 2014 and 2013 (In Thousands):

	CH Energy Group Year Ended December 31,			Central Hudson Year Ended December 31,		
	2015	2014	2013	2015	2014	2013
Share Unit Plan Units	$ 994	$ 1,390	$ 7,292	$ 1,074	$ 566	$ 1,222
Restricted shares and stock units	$ -	$ -	$ 875	$ -	$ -	$ 134
Recognized tax benefit of restricted shares and stock units	$ -	$ -	$ 349	$ -	$ -	$ 54

The liabilities associated with the SUPs are recorded at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight line basis. The fair value of the SUPs' liabilities are based on the Fortis common share 5 day volume weighted average trading price at the end of each reporting period and the expected payout based on management's best estimate in accordance with the defined metrics of each grant.

Under the SUP agreements, the amount of any outstanding awards payable to an employee who resigns for Good Reason, as defined in the employee's employment agreement, and who has 25 years or more of service with the Company under the terms of the 2014 SUP or 15 years of service under the terms of the 2015 SUP is determined as if the employee continued to be an employee through the end of the performance period. In accordance with ASU 2014-12, in this situation, compensation expense for that individual is recognized over the requisite service period, instead of the performance period. As a result, calendar year 2014 SUP Unit expense included additional compensation expense to recognize the payment due to a CH Energy Group officer with outstanding awards who elected to resign for Good Reason under the officer's employment agreement and who had over 25 years of service. In addition, in the second quarter of 2015, additional expense was recognized in accordance with ASU 2014-12 for Central Hudson Officers that are retirement eligible under terms of the SUP agreement in which they have attained the required retirement age and met the required 15 years of service.

Prior to the acquisition of CH Energy Group by Fortis, compensation expense for performance shares was recognized over the three year performance period based on the fair value of the awards at the end of each reporting period and the time elapsed within each grant's performance period. The fair value of performance shares was determined based on the shares' current market value at the end of each reporting period, estimated forfeitures for each grant, and expected payout based on management's best estimate including analysis of historical performance in accordance with the defined metrics of each grant. Compensation expense was recorded as performance shares were earned over the relevant three-year life of the performance share grant prior to its award. Compensation expense for restricted shares prior to the acquisition by Fortis was recognized over the defined vesting periods based on the grant date fair value of the awards.

Immediately prior to the completion of the acquisition of CH Energy Group by Fortis, all remaining unvested performance shares, restricted stock shares and restricted stock units vested were cancelled in exchange for cash payments. As a result of the acceleration, additional expense of $5.8 million related to performance shares and $0.7 million related to restricted shares and restricted stock units was recognized by CH Energy Group in the second quarter of 2013 and not allocated to its subsidiaries.

Deferred Stock Units

Prior to the acquisition of CH Energy Group by Fortis Inc., CH Energy Group provided equity compensation for its non-employee Directors. Each Director was required to accumulate within 5 years, and to hold during his or her service on the Board, at least 6,000 shares of CH Energy Group’s Common Stock (which could be in the form of deferred stock units). Following the merger, non-employee directors no longer receive equity compensation.

There was no equity compensation expense to non-employee Directors for the year ended December 31, 2015 and 2014. Total equity compensation expense to non-employee Directors recognized by CH Energy Group was $0.3 million for the year ended December 31, 2013.

NOTE 12 – Commitments and Contingencies

Electricity Purchase Commitments

In 2014, Central Hudson entered into two agreements with Entergy Nuclear Power Marketing, LLC to purchase electricity on a unit contingent basis at defined prices from December 1, 2014 through March 31, 2015. Energy supplied under these agreements cost approximately $11.5 million, of which $8.5 million related to 2015. These contracts expired on March 31, 2015 and were not renewed.

In 2015, Central Hudson entered into an agreement with Entergy Nuclear Power Marketing, LLC to purchase electricity on a unit contingent basis at defined prices from June 1, 2015 through August 31, 2015. Energy supplied under this agreement cost approximately $2.0 million. This contract expired on August 31, 2015 and was not renewed.

In 2015, Central Hudson entered into an agreement with Entergy Nuclear Power Marketing, LLC to purchase electricity on a unit contingent basis at defined prices from December 1, 2015 through March 31, 2016. Energy supplied under this agreement cost approximately $1.7 million in 2015.

In 2015, Central Hudson entered into an agreement with Entergy Nuclear Power Marketing, LLC to purchase electricity on a unit contingent basis at defined prices from June 1, 2016 through August 31, 2016.

Currently, Central Hudson meets its capacity and electricity obligations through contracts with capacity and energy providers, purchases from the NYISO energy and capacity markets and its own generating capacity.

In November 2013, Central Hudson entered into a contract to purchase 200 megawatts of installed capacity from the Roseton Generating Facility from May 2014 through April 2017, with $14.2 million in purchase commitments remaining as of December 31, 2015. In June 2014, Central Hudson entered into a contract to purchase available installed capacity from the Danskammer Generating Facility from October 2014 through August 2018 with approximately $75.9 million in purchase commitments remaining as of December 31, 2015.

Operating Leases

CH Energy Group and its subsidiaries have entered into agreements with various companies which provide products and services to be used in their normal operations. These agreements include operating leases for the use of data processing and office equipment and vehicles. The provisions of these leases generally provide for renewal options and some contain escalation clauses.

Operating lease rental payment amounts charged to expense by Central Hudson were $1.4 million for 2015, $1.5 million for 2014 and $1.7 million for 2013, respectively.

In addition to Central Hudson's operating lease rental payments, CH Energy Group had additional operating lease rental payments that were immaterial for 2015 and 2014 and $0.8

million for 2013, which were related to Griffith and therefore are included in Discontinued Operations on the CH Energy Group Consolidated Statement of Income.

Future minimum lease payments excluding executory costs, such as property taxes and insurance, are included in the following table of Other Commitments. All leases are non-cancelable and rent expense is recognized on a straight-line basis over the minimum lease term.

Other Commitments

The following is a summary of commitments for CH Energy Group and its affiliates as of December 31, 2015 (In Thousands):

	Projected Payments Due By Period						
	Less than 1 year	Year Ending 2017	Year Ending 2018	Year Ending 2019	Year Ending 2020	Thereafter	Total
Operating Leases	$ 1,784	$ 1,680	$ 1,675	$ 1,506	$ 1,476	$ 380	$ 8,501
Purchased Electric Contracts(1)	57,149	37,377	20,581	2,399	2,399	3,613	123,518
Purchased Natural Gas Contracts(1)	28,140	16,120	10,714	9,535	3,336	7,166	75,011
Repayments of Long-Term Debt	9,315	34,406	31,503	28,607	17,718	422,496	544,045
Interest Obligations on Long-Term Debt	23,555	23,022	21,267	20,655	18,953	255,794	363,246
Total	$ 119,943	$ 112,605	$ 85,740	$ 62,702	$ 43,882	$ 689,449	$ 1,114,321

(1) Purchased electric and purchased natural gas costs for Central Hudson are fully recovered via their respective regulatory cost adjustment mechanisms.

The following is a summary of commitments for Central Hudson as of December 31, 2015 (In Thousands):

	Projected Payments Due By Period						
	Less than 1 year	Year Ending 2017	Year Ending 2018	Year Ending 2019	Year Ending 2020	Thereafter	Total
Operating Leases	$ 1,784	$ 1,680	$ 1,675	$ 1,506	$ 1,476	$ 380	$ 8,501
Purchased Electric Contracts(1)	57,149	37,377	20,581	2,399	2,399	3,613	123,518
Purchased Natural Gas Contracts(1)	28,140	16,120	10,714	9,535	3,336	7,166	75,011
Repayments of Long-Term Debt	8,000	33,000	30,000	27,000	16,000	411,950	525,950
Interest Obligations on Long-Term Debt	22,347	21,905	20,246	19,739	18,148	253,723	356,108
Total	$ 117,420	$ 110,082	$ 83,216	$ 60,179	$ 41,359	$ 676,832	$ 1,089,088

(1) Purchased electric and purchased natural gas costs for Central Hudson are fully recovered via their respective regulatory cost adjustment mechanisms.

Other Contractual Obligations

CHET was established to be an investor in Transco, which was created to develop, own and operate electric transmission projects in New York State. In December 2014, Transco filed an application with the FERC for the recovery through a formula rate, the cost of and a return on five high voltage transmission projects totaling $1.7 billion. CHET's maximum commitment for these five projects is $182 million, which is the maximum budgeted amount for these projects at 100% equity. Pending regulatory approvals by the FERC and PSC, CHET's equity investment will approximate $7.8 million in 2016.

CH Energy Group issued a parental guarantee to Transco to assure the payment of CHET's maximum commitment of $182 million. As of December 31, 2015, CHET does not have any project commitments to Transco. Management is not aware of any existing condition that would require any payments under this guarantee.

Capital Expenditures: Central Hudson is a regulated utility and, as such, is obligated to provide service to customers within its service territory. Central Hudson's capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electric and gas systems and to meet customer growth. Central Hudson's capital expenditure program is forecasted to be approximately $165 million for 2016.

Central Hudson is required to meet its contractual benefit payment obligations. Decisions about how to fund the Retirement Plan to meet these obligations are made annually and are primarily affected by the discount rate used to determine benefit obligations, current asset values, corporate resources and the projection of Retirement Plan assets. Based on the funding requirements of the Pension Protection Act, Central Hudson plans to make contributions that maintain the funded percentage at 80% or higher. Central Hudson is not expected to make any contributions in 2016 due to the higher than expected contributions made in 2015 of $21.3 million resulting in a funded status that meets Central Hudson's objective. The actual contributions could vary significantly based upon economic growth, projected investment returns, inflation and interest rate assumptions. Actual funded status could vary significantly based on asset returns and changes in the discount rate used to estimate the present value of future obligations.

Environmental Matters

Central Hudson

- Site Investigation and Remediation ("SIR") Program

Central Hudson and its predecessors owned and operated manufactured gas plants ("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 ("DEC"), which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes Central Hudson or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that Central Hudson investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Cleanup Agreement, or Brownfield Cleanup Agreement. The DEC has placed all seven of these sites on the New York State Environmental Site Remediation Database. As authorized by the PSC, Central Hudson is currently permitted to defer for future recovery the 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. In a June 26, 2013 Order (Case 12-M-192) the PSC modified the deferral for MGP and non-MGP sites to apply to all Environmental SIR costs incurred by Central Hudson during the period from July 1, 2013 to June 30, 2015. Under the 2013 Order, Central Hudson included two additional Environmental SIR sites and is currently permitted to defer for future recovery the differences between actual costs for Environmental SIR costs and the associated rate allowances with carrying charges. In a June 17, 2015 Order, Cases 14-E-0318 and 14-G-0319, the deferral was reaffirmed and extended through June 30, 2018.

Site investigation and remediation can be divided into various stages of completion based on the milestones of activities completed and reports reviewed. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated at a point in time. These stages, the types of costs accrued during various stages and the sites currently in each stage include:

1. *Investigation* – Begins with preliminary investigations and is completed upon filing and approval by DEC of a Remedial Investigation ("RI") Report. Central Hudson accrues for estimated investigation costs.

2. *Remedial Alternatives Analysis ("RAA")* – Engineering analysis of alternatives for remediation based on the RI is compiled into a RAA Report. Upon completion of the RAA and the filing with the DEC, management accrues for an estimate of remediation costs developed and quantified in the RAA based on DEC approved methods, as well as an estimate of post-remediation operation, maintenance and monitoring costs ("OM&M"). These amounts represent a significant portion of the total costs to remediate and are subject to change based on further investigations, final remedial design and associated engineering estimates, regulatory comments and requests, remedial design changes/negotiations and changed or unforeseen conditions during the remediation or additional requirements following the remediation. Prior to the completion of the RAA, management cannot reasonably estimate what cost will be incurred for remediation or post-remediation activities.

   - **Site #5 – North Water Street** – RAA in Progress
     - Field activities associated with the former propane tank area investigation have been completed and the DEC has approved the report of findings. Based on the results of this investigation, some level of future remediation may be required in this area.
     - The DEC released a Fact Sheet in October 2015 with a 45-day public comment period. The DEC and New York State Department of Health ("NYSDOH"), assisted by Central Hudson, conducted a public meeting to discuss the RAA Report and Fact Sheet. The DEC is currently developing/finalizing a Decision Document in consideration of comments received during the public comment period. After the Decision Document is finalized, the Remedial Design ("RD") will begin.

- Approximately $57.5 million was accrued in May 2014 based on the scope of work and cost estimate developed for remediation and OM&M activities in the RAA Report.

3. *Remedial Design* - Upon approval of the RAA and final decision of remediation approach based on alternatives presented, a RD is developed and filed with the DEC for approval.

   - **Site #6 – Kingston** – RD in Progress
     - The DEC approved the RAA Report in July 2014. Additionally, the DEC released a Fact Sheet in November 2014 inviting the public to comment on the proposed site remedy outlined in the RAA. The comment period ended in January 2015 with no comments received. Subsequently, the DEC issued a Decision Document in June 2015.
     - Pre-design investigation activities were completed between August and September 2014 and a report of findings was submitted to the DEC for review and approval in December 2014. The DEC provided comments on the report of findings in January 2015. A follow up meeting was held with the DEC in May 2015, whereby, they agreed to limit dredging of polycyclic aromatic hydrocarbon ("PAH") impacted sediments to a small portion of the area located east of the gas crossing.
     - The draft RD Report was submitted to the DEC for review and approval in July 2015. Subsequently, the DEC issued a RD Report modification letter in September 2015. A revised RD Report was submitted to the DEC for review and approval in December 2015.
     - A remedial construction "Design-Build" request for proposal ("RFP") was sent to prospective environmental engineering firms for competitive bidding in September 2015. A pre-bid meeting was conducted and proposals were received by Central Hudson in the fourth quarter for evaluation.
     - Approximately $33 million was accrued in December 2013 and an additional $1.5 million in June 2014 based on the scope of work and cost estimate developed for remediation and OM&M activities in the RAA Report. However, based on bids received in 2015, the accrual was reduced by approximately $11.5M

   - **Site # 8 - Eltings Corners** – RD in Progress
     - In July 2014, Central Hudson submitted a draft Corrective Measures Study scoping document for review by the DEC. Subsequently Central Hudson proceeded to prepare and submit a Focused Corrective Measures Study Report ("FCMS") to the DEC for their review and approval.
     - The DEC approved the FCMS in December 2014 and issued a draft Statement of Basis ("SB") for public review and comment in February 2015. The comment period subsequently ended in March 2015 with no significant comments received as determined by the DEC. As a result, the DEC issued the Final SB in March 2015.
     - The DEC is preparing a Draft Permit Modification to the facility's Hazardous Waste Storage Permit and once finalized, remediation work activity can be planned, scheduled and implemented accordingly.

4. *Remediation* – Completion of the work plan as defined in the approved RD. Upon completion, final reports are filed with the DEC for approval and may include a Construction Completion Report ("CCR"), Final Engineering Report ("FER"), or other reports required by the DEC based on the work performed.

- **Site #2 – Newburgh Area A** – Remedial Activities in Progress
  - In 2012, Central Hudson retired and removed propane air facilities located on Area A.
  - In March 2014, approximately $5 million was accrued based on this scope of work and cost estimate developed for remediation of the former propane tank area.
  - Central Hudson submitted a Remedial Action Work Plan ("RAWP"), detailing proposed remedial activities in Area A, to the DEC for review and approval in May 2015. Subsequently, the DEC approved the RAWP in June 2015.
  - Contracts were executed with a remedial contractor and environmental engineering firm in September 2015 to complete the supplemental remedial activities detailed in the RAWP. Central Hudson submitted the Health and Safety Plan ("HASP") and Site Operations Plan ("SOP"), associated with Area A remedial activities, to the DEC and NYSDOH for review and approval in October 2015. Subsequently, the DEC provided comments on the SOP and a revised SOP was submitted and approved by the DEC in October 2015. Site mobilization activities commenced in October 2015 and remedial activities were completed during January 2016.

5. *Post-Remediation Monitoring* – Entails the OM&M as directed by the DEC based on the approved final report of remediation. The activities are typically defined in a Site Management Plan ("SMP"), which is approved by the DEC. The extent of activities during this phase may increase or decrease based on the results of ongoing monitoring being performed and future potential usage of the property.

- **Site #2 – Newburgh Area B and C** – Post-Remediation In Progress
  - Field activities associated with the sediment documentation sampling of surface sediments in both the non-aqueous phase liquid ("NAPL") and PAH dredge areas in Area C were completed in September 2014. The results were subsequently submitted to the DEC for review in November 2014.
  - Amounts accrued represent an estimate of costs for OM&M and execution of the draft SMP related to the previously remediated area of site.

- **Site #3 – Laurel Street** – Post-Remediation In Progress
  - The Interim SMP was approved by the DEC in January 2015.
  - The Voluntary Cleanup Agreement ("VCA") Amendment Application was approved by the DEC in July 2015. Additionally, the DEC executed the Environmental Easement ("EE") in August 2015 which was then filed with the Dutchess County Clerk in September 2015.
  - Amounts accrued represent an estimate of costs for OM&M.

- **Site #4 – Catskill** – Post-Remediation In Progress
  - The final FER, including the executed EEs, were approved by the DEC in December 2014 and a Certificate of Completion ("COC") was issued on the same day.
  - Amounts accrued represent an estimate of costs to complete the post-remediation and OM&M.

- *No Action Required*

  - **Site #1 – Beacon** – No Action Required
    - The SMP was submitted to the DEC and a release letter for the site was received in 2013.
    - No further costs are expected and no amounts are accrued related to this site.
    - If the building at this site were to be removed, further investigation and testing would be required related to the soil under the building, which may require additional remediation. Management cannot currently estimate the likelihood of the building being removed or the costs that may be incurred related to this.

  - **Site #7 – Bayeaux Street** – No further investigation or remedial action is currently required. However, per the DEC this site still remains on the list for potential future investigation.

  - **Site # 9 – Little Britain Road** - There has been no change to this site in 2015, however, the relevant historical disclosure is provided as required.
    - In 2000, Central Hudson and the DEC entered into a VCA whereby Central Hudson removed approximately 3,100 tons of soil and conducted groundwater sampling.
    - Central Hudson believes that it has fulfilled its obligations under the VCA and should receive the release provided for in the VCA, but the DEC has proposed that additional groundwater work be done to address groundwater sampling results that showed the presence of certain contaminants at levels exceeding the DEC criteria.
    - Central Hudson believes that such work is not necessary and has completed a soil vapor intrusion study showing that indoor air at the facility met Occupational Safety and Health Administration ("OSHA") and NYSDOH standards.
    - In October 2011, the DEC requested a 'non-committal' meeting with Central Hudson to discuss the site and possible next steps. At the annual MGP meeting with Central Hudson in October 2012, the DEC discussed the Little Britain Road property requesting an upcoming meeting to discuss the site and possible next steps. Central Hudson responded that it was available for such a meeting. A meeting date has yet to be established.
    - At this time Central Hudson does not have sufficient information to estimate the need for additional remediation or potential remediation costs. Central Hudson has put its insurers on notice regarding this matter and intends to seek reimbursement from its insurers for amounts, if any, for which it may become liable. Central Hudson cannot predict the outcome of this matter.

A summary of amounts accrued and spent are detailed in the chart below (In Thousands):

Site #	Liability Recorded as of 12/31/14	Amounts Spent in 2015	Liability Adjustment	Liability Recorded as of 12/31/15	Current Portion of Liability at 12/31/15	Long-Term Portion of Liability at 12/31/15
2, 3, 4, 5, 6 and 8	$ 106,943	$ 2,368	$ (12,456)	$ 92,119	$ 22,998	$ 69,121

Based on a cost model analysis completed in 2014 of possible remediation and future OM&M costs for sites #1 through #6 and #8 above, Central Hudson believes there is a 90%

confidence level that the total costs to remediate these sites will not exceed $168.7 million over the next 30 years. The total cost is derived from the summation of the 90% confidence level adjusted for inflation for each individual site. The cost model involves assumptions relating to investigation expenses, results of investigations, remediation costs, potential future liabilities, and post-remedial OM&M costs, and is based on a variety of factors including projections regarding the amount and extent of contamination, the location, size and use of the sites, proximity to sensitive resources, status of regulatory investigations, and information regarding remediation activities at other SIR sites in New York State. The cost model also assumes that proposed or anticipated remediation techniques are technically feasible and that proposed remediation plans receive DEC and NYSDOH approval.

Future remediation activities, including OM&M and related costs may vary significantly from the assumptions used in Central Hudson's current cost estimates, and these costs could have a material adverse effect (the extent of which cannot be reasonably determined) on the financial condition, results of operations and cash flows of CH Energy Group and Central Hudson if Central Hudson were unable to recover all or a substantial portion of these costs via collection in rates from customers and/or through insurance.

Central Hudson expects to recover its remediation costs from its customers. The current components of this recovery include:

- The 2015 Rate Order includes cash recovery of approximately $18.9 million during the three year period ending June 30, 2018.
- As part of the 2015 Rate Order, Central Hudson maintained previously granted deferral authority and subsequent recovery for amounts spent over the rate allowance.
- The Environmental SIR costs recovered through rates and other regulatory mechanisms from July 1, 2007 through December 31, 2015 was approximately $38.9 million, with $5.3 million recovered in 2015.
- The total spent in the year ended December 31, 2015 related to site investigation and remediation was approximately $2.4 million.
- The regulatory asset balance as of December 31, 2015 was $87.2 million, which represents the difference between amounts spent or currently accrued as a liability and the amounts recovered through a rate allowance, as well as carrying charges accrued.

Central Hudson has put its insurers on notice and intends to seek reimbursement from its insurers for its costs. Certain of these insurers have denied coverage. In addition to the rate allowance amounts noted above, Central Hudson has recovered approximately $2.8 million from insurance. There were no insurance recoveries in 2015. We do not expect insurance recoveries to offset a meaningful portion of total costs.

Other Matters

Asbestos Litigation

As of December 31, 2015, of the 3,350 asbestos cases brought against Central Hudson, 1,167 remain pending. Of the cases no longer pending against Central Hudson, 2,027 have been dismissed or discontinued without payment by Central Hudson, and Central Hudson has settled 156 cases. Central Hudson is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including Central Hudson's experience in settling asbestos cases and in obtaining dismissals of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material adverse effect on the financial position, results of operations or cash flows of either CH Energy Group or Central Hudson.

Other Litigation

CH Energy Group and Central Hudson are involved in various other legal and administrative proceedings incidental to their businesses, which are in various stages. While these matters collectively could involve substantial amounts, based on the facts currently known, it is the opinion of management that their ultimate resolution will not have a material adverse effect on either CH Energy Group's or Central Hudson's financial positions, results of operations or cash flows.

CH Energy Group and Central Hudson expense legal costs as incurred.

NOTE 13 – Segments and Related Information

CH Energy Group's reportable operating segments are the regulated electric utility business and regulated natural gas utility business of Central Hudson and the unregulated fuel distribution business of Griffith, prior to its divestiture on March 4, 2014. Other activities of CH Energy Group, which do not constitute a business segment, include CHEC's remaining energy investments, CHET's investment in Transco and the holding company's activities, which consist primarily of financing its subsidiaries, and are reported under the heading "Other Businesses and Investments."

General corporate expenses and Central Hudson's property common to both electric and natural gas segments have been allocated in accordance with practices established for regulatory purposes. From January 1, 2015 through June 30, 2015, the common allocation was 85% for electric and 15% for gas. Beginning July 1, 2015, per the terms of the 2015 Rate Order, allocation changed to 80% for electric and 20% for gas.

On March 4, 2014, CHEC completed the sale of Griffith to Star Gas Partners, L.P. Therefore, operating results of Griffith are reported as discontinued operations for all periods presented in the Consolidated CH Group Statement of Income. The segment information presented below for Griffith includes the operating results for this segment. The reclassification of these results to discontinued operations is presented in the Elimination column in order to reconcile the total to the amounts presented in the Consolidated CH Energy Group Statement of Income.

CH Energy Group Segment Disclosure

(In Thousands)

	Year Ended December 31, 2015				
	Segments		Other Businesses and Investments	Eliminations	Total
	Central Hudson				
	Electric	Natural Gas			
Revenues from external customers	$ 544,296	$ 146,562	$ -	$ -	$ 690,858
Intersegment revenues	14	224	-	(238)	-
Total revenues	544,310	146,786	-	(238)	690,858
Depreciation and amortization	34,198	9,876	-	-	44,074
Operating Income (loss)	77,021	23,748	(237)	-	100,532
Interest and investment income	3,393	158	34	-	3,585
Interest charges	23,906	6,202	1,303	-	31,411
Income (loss) before income taxes	57,324	19,410	(1,866)	-	74,868
Income tax expense (benefit)	22,332	8,814	(18)	-	31,128
Net Income (Loss) Attributable to CH Energy Group	34,992	10,596	(1,848)	-	43,740
Segment assets at December 31	1,445,143	458,889	15,181	(1,655)	1,917,558
Capital expenditures	98,647	42,001	-	-	140,648

CH Energy Group Segment Disclosure

(In Thousands)

	Year Ended December 31, 2014					
	Segments			Other Businesses and Investments	Eliminations	Total
	Central Hudson					
	Electric	Natural Gas	Griffith			
Revenues from external customers	$ 579,757	$ 163,005	$ 85,856 (3)	$ -	$ (85,856)	$ 742,762
Intersegment revenues	12	345	-	-	(357)	-
Total revenues	579,769	163,350	85,856 (3)	-	(86,213)	742,762
Depreciation and amortization	33,844	10,015	-	-	-	43,859
Operating Income (loss)	67,900	14,476	7,342 (3)(4)	(8,328)	(7,000)	74,390
Interest and investment	3,904	451	-	474	(434)	4,395
Interest charges	24,858	6,713	425 (3)	1,541	(434)	33,103
Income (loss) before income taxes	47,731	8,474	5,671 (3)	(105) (5)	(14,944)	46,827
Income tax expense	17,494	4,867	2,325 (4)	2,765	(7,255)	20,196
Net Income (Loss) Attributable to CH Energy Group	30,236	3,608	3,346 (1)	(2,870) (2)	-	34,320
Segment assets at December 31	1,343,127	522,581	-	8,198	(1,615)	1,872,291
Capital expenditures	80,380	32,811	129	-	-	113,320

(1) Includes net income of $3,376 related to Griffith's earnings that are allocated to Discontinued Operations.

(2) Includes net income from Discontinued Operations of $5,128 related to Other Businesses & Investments earnings, including the gain on sale that is allocated to Discontinued Operations. A combined filing tax detriment of $1,067 recorded at the Holding Company as the net result of the gain on Griffith sale and impacts of current year Griffith's operations is included in Discontinued Operations. In addition, the amount includes $251 related to interest income at the Holding Company for inter-company funding of Griffith debt.

(3) Amount represents Discontinued Operations and has been classified as such in the CH Energy Group Consolidated Statement of Income. This amount is included in the Eliminations column as a reconciliation to the Income Statement presentation.

(4) This amount includes ($51) of overhead charges and associated tax benefit billed to Griffith that will be re-allocated to Central Hudson in future years following the sale of Griffith. As such, the amount shown in the elimination column due to the reclassification of Discontinued Operations for this line item does not remove the impact of the overhead charges previously discussed.

CH Energy Group Segment Disclosure

(In Thousands)

	Year Ended December 31, 2013					
	Segments			Other		
	Central Hudson			Businesses		
		Natural		and		
	Electric	Gas	Griffith	Investments	Eliminations	Total
Revenues from external customers	$ 532,539	$ 135,904	$ 298,367 (5)	$ -	$ (298,367)	$ 668,443
Intersegment revenues	11	245	-	-	(256)	-
Total revenues	532,550	136,149	298,367 (5)	-	(298,623)	668,443
Depreciation and amortization	31,436	8,782	4,994	-	(4,994)	40,218
Operating income (loss)	41,114	15,333	6,334 (1)	(16,485)	(7,298)	38,998
Interest and investment income	5,015	823	-	2,289	(2,243)	5,884
Interest charges	25,073	6,650	2,248 (5)	2,036	(2,248)	33,759
Income (loss) before income taxes	22,054	9,893	4,333 (1)	(18,675)	(5,297)	12,308
Income tax expense (benefit)	7,237	4,411	1,777 (1)	(3,679)	(2,172)	7,574
Net Income (Loss) Attributable to CH Energy Group	14,141	5,302	2,557 (2)	(13,674) (3)	-	8,326
Segment assets at December 31	1,232,979	430,775	110,361 (4)	10,940	(721)	1,784,334
Capital expenditures	75,945	32,872	2,155	-	-	110,972

(1) This amount includes ($964) of overhead charges and associated tax benefit billed to Griffith that will be re-allocated to Central Hudson in future years upon the completion of the Griffith sale. As such, the amount shown in the Elimination column related to the reclassification of discontinued operations for this line item does not remove the impact of the overhead charges previously discussed.

(2) Includes net income from discontinued operations of $3,125 related to Griffith's earnings that are allocated to discontinued operations.

(3) Includes net income from discontinued operations of $1,323 related to interest income at the Holding Company for funding of Griffith debt.

(4) Includes assets held for sale of $105,151 related to Griffith.

(5) Amount represents Discontinued Operations and has been classified as such in the CH Energy Group Consolidated Statement of Income. This amount is included in the Eliminations column as a reconciliation to the Income Statement presentation.

NOTE 14 – Accounting for Derivative Instruments and Hedging Activities

Purpose of Derivatives

Central Hudson enters into derivative contracts in conjunction with the Company's energy risk management program to hedge certain risk exposure related to its business operations. The derivative contracts are typically either exchange-traded or over-the-counter ("OTC") instruments. The primary risks the Company seeks to manage by using derivative instruments are interest rate risk, commodity price risk and adverse or unexpected weather conditions. Central Hudson uses derivative contracts to reduce the impact of volatility in the prices of natural gas and electricity and to hedge exposure to volatility in interest rates for its variable rate long-term debt. Derivative transactions are not used for speculative purposes. Central Hudson derivative activities consist of the following:

- Interest rate caps are used to minimize interest rate risks and to improve the matching of assets and liabilities. An interest rate cap is an interest rate option agreement in which payments are made by the seller of the option when the reference rate exceeds the specified strike rate (or the set rate at which the option contract can be exercised). The purpose of these agreements is to reduce exposure to rising interest rates while still having the ability to take advantage of falling interest rates by putting a "cap" on the interest rate Central Hudson pays on debt for which such caps are purchased.
- Natural gas futures are used to minimize commodity price volatility for natural gas purchases. A natural gas futures contract is a standardized contract to buy or sell a specified commodity (natural gas) of standardized quality at a certain date in the future, at a market determined price (the futures price). Central Hudson's reason for purchasing these contracts is to reduce price fluctuations for natural gas and the impact of volatility in the commodity markets on its customers.
- Natural gas swaps and contracts for differences (electricity swaps) are used to minimize commodity price volatility for natural gas and electricity purchases for Central Hudson's full service customers. A swap contract or a contract for differences is the exchange of two payment streams between two counterparties where the cash flows are dependent on the price of the underlying commodity. In an effort to moderate commodity price volatility, Central Hudson enters into contracts to pay a fixed price and receive market price for a defined commodity and volume. These contracts are aligned with Central Hudson's actual commodity purchases at market price, resulting in a net fixed price payment.

At December 31, 2015, Central Hudson had open derivative contracts related to natural gas purchases during January 2016 - March 2016, for 1.18 million Dth, which covers approximately 34.7% of Central Hudson's projected total natural gas supply requirements during this period. At December 31, 2014, Central Hudson had open derivative contracts related to natural gas purchases during January 2015 - March 2015, for 1.44 million Dth, which covered approximately 43.5% of Central Hudson's projected total natural gas supply requirements during that period. In 2015, derivative transactions covered approximately 26.8% of Central Hudson's total natural gas supply requirements as compared to 24.3% in 2014.

Additionally, Central Hudson had open derivative contracts related to electricity purchases at December 31, 2015 for 2.43 million MWh, which covers the following approximate percentages of its projected electricity requirements in 2016 – 2019:

Year	Percentage
2016	36.5%
2017	25.6%
2018	15.5%
2019	7.8%

In 2015, OTC derivative contracts covered approximately 54.6% of Central Hudson's total electricity supply requirements as compared to 58.9% in 2014.

Accounting for Derivatives

The gains and losses associated with Central Hudson's derivatives are included as part of Central Hudson's commodity cost and/or price-reconciled in its natural gas and electricity cost adjustment charge clauses, and are not designated as hedges. Additionally, Central Hudson has been authorized to fully recover the interest costs associated with its variable rate Series B NYSERDA Bonds and 2014 Series E Bonds, which includes costs and gains and losses associated with its interest rate cap contracts. As a result, derivative activity at Central Hudson does not impact earnings.

Derivative Risks

The basic types of risks associated with derivatives are market risk (that the value of the derivative will be adversely impacted by changes in the market, primarily the change in commodity prices, interest and exchange rates) and credit risk (that the counterparty will not perform according to the terms of the contract). The market risk of the derivatives generally offset the market risk associated with the hedged commodity.

The majority of Central Hudson's derivative instruments contain provisions that require the Company to maintain specified issuer credit ratings and financial strength ratings. Should the Company's ratings fall below these specified levels, it would be in violation of the provisions, and the derivatives' counterparties could terminate the contracts and request immediate payment.

To help limit the credit exposure of their derivatives, Central Hudson enters into master netting agreements with counterparties whereby contracts in a gain position can be offset against contracts in a loss position. Of the 15 total agreements held by Central Hudson, 8 contain credit-risk related contingent features. As of December 31, 2015, there were 13 open derivative contracts under these 8 master netting agreements containing credit-risk related contingent features, all of which were in a liability position. The circumstances that could trigger these features, the aggregate fair value of the derivative contracts that contain contingent features and the amount that would be required to settle these instruments on December 31, 2015 if the contingent features were triggered, are described below.

Contingent Contracts
(Dollars In Thousands)

	As of December 31, 2015		
Triggering Event	# of Contracts in a Liability Position Containing the Triggering Feature	Gross Fair Value of Contract	Cost to Settle if Contingent Feature is Triggered (net of collateral)
Central Hudson:			
Change in Ownership	1	$ (86)	$ (86)
Credit Rating Downgrade	11	$ (2,897)	$ (2,897)
Adequate Assurance	1	(407)	(407)
Total Central Hudson	13	$ (3,390)	$ (3,390)

CH Energy Group and Central Hudson have elected gross presentation for their derivative contracts under master netting agreements and collateral positions. On December 31, 2015 and December 31, 2014, Central Hudson did not have collateral posted against the fair value amount of derivatives.

The net presentation for CH Energy Group's and Central Hudson's derivative assets and liabilities as of December 31, 2015 and 2014 are as follows (In Thousands):

				Gross Amounts Not Offset in the Statement of Financial Position		
Description	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2015						
Derivative Contracts:						
Central Hudson - electric	$ 2,218	$ -	$ 2,218	$ 2,218	$ -	$ -
Central Hudson - natural gas	-	-	-	-	-	-
Total Central Hudson and CH Energy Group Assets	$ 2,218	$ -	$ 2,218	$ 2,218	$ -	$ -
As of December 31, 2014						
Derivative Contracts:						
Central Hudson - electric	$ 570	$ -	$ 570	$ 570	$ -	$ -
Central Hudson - natural gas	-	-	-	-	-	-
Total Central Hudson and CH Energy Group Assets	$ 570	$ -	$ 570	$ 570	$ -	$ -

				Gross Amounts Not Offset in the Statement of Financial Position		
Description	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2015						
Derivative Contracts:						
Central Hudson - electric	$ 10,628	$ -	$ 10,628	$ 2,218	$ -	$ 8,410
Central Hudson - natural gas	990	-	990	-	-	990
Total Central Hudson and CH Energy Group Liabilities	$ 11,618	$ -	$ 11,618	$ 2,218	$ -	$ 9,400
As of December 31, 2014						
Derivative Contracts:						
Central Hudson - electric	$ 5,873	$ -	$ 5,873	$ 570	$ -	$ 5,303
Central Hudson - natural gas	1,854	-	1,854	-	-	1,854
Total Central Hudson and CH Energy Group Liabilities	$ 7,727	$ -	$ 7,727	$ 570	$ -	$ 7,157

Gross Fair Value of Derivative Instruments

Current accounting guidance related to fair value measurements establishes a fair value hierarchy to prioritize the inputs used in valuation techniques based on observable and unobservable data, but not the valuation techniques themselves. Observable inputs are inputs that reflect the assumptions market participants would use in pricing the asset or liability. Unobservable inputs are inputs that reflect the reporting entity's own assumptions about the assumptions market participants would use in pricing an asset or a liability. Classification of inputs is determined based on the lowest level input that is significant to the overall valuation. The fair value hierarchy prioritizes the inputs to valuation techniques into the three categories described below:

Level 1 Inputs: Quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 Inputs: Directly or indirectly observable (market-based) information. This includes quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.

Level 3 Inputs: Unobservable inputs for the asset or liability for which there is either no market data, or for which asset and liability values are not correlated with market value.

Derivative contracts are measured at fair value on a recurring basis. As of December 31, 2015 and 2014, CH Energy Group's and Central Hudson's derivative assets and liabilities by category and hierarchy level are as follows (In Thousands):

Asset or Liability Category	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
As of December 31, 2015[(1)]				
Assets:				
Derivative Contracts:				
Central Hudson - electric	$ 2,218	$ -	$ -	$ 2,218
Central Hudson - natural gas	-	-	-	-
Total CH Energy Group and Central Hudson Assets	$ 2,218	$ -	$ -	$ 2,218
Liabilities:				
Derivative Contracts:				
Central Hudson - electric	$ (10,628)	$ -	$ -	$ (10,628)
Central Hudson - natural gas	(990)	(990)	-	-
Total CH Energy Group and Central Hudson Liabilities	$ (11,618)	$ (990)	$ -	$ (10,628)
As of December 31, 2014[(1)]				
Assets:				
Derivative Contracts:				
Central Hudson - electric	$ 570	$ -	$ -	$ 570
Total CH Energy Group and Central Hudson Assets	$ 570	$ -	$ -	$ 570
Liabilities:				
Derivative Contracts:				
Central Hudson - electric	$ (5,873)	$ -	$ -	$ (5,873)
Central Hudson - natural gas	(1,854)	(1,854)	-	-
Total CH Energy Group and Central Hudson Liabilities	$ (7,727)	$ (1,854)	$ -	$ (5,873)

(1) Interest rate cap agreements are not shown in the above chart. These are classified as Level 2 in the fair value hierarchy using SIFMA Municipal Swap Curves and 3 month US Dollar Libor rate forward curves. At December 31, 2015 and 2014 the fair value was $0.

Central Hudson obtains forward pricing for Level 3 derivatives from an independent third party provider of derivative pricing. Significant unobservable inputs utilized in their pricing model are bi-lateral contracts and projected activity of certain major participants.

The table listed below provides a reconciliation of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 in the fair value hierarchy (In Thousands):

	Year Ended December 31, 2015	Year Ended December 31, 2014
Balance at Beginning of Period	$ (5,303)	$ 9,898
Unrealized losses	(3,107)	(15,201)
Realized gains/(losses)	(14,773)	15,761
Purchases	-	-
Issuances	-	-
Sales and settlements	14,773	(15,761)
Transfers in and/or out of Level 3	-	-
Balance at End of Period	$ (8,410)	$ (5,303)
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to derivatives still held at end of period	$ -	$ -

There were no transfers into or out of Levels 1 or 2.

CH Energy Group's derivative contracts are typically either exchange-traded or OTC instruments. Exchange-traded and OTC derivatives are valued based on listed market prices. On December 31, 2015, Central Hudson's derivative contracts were comprised of swap contracts for electricity and natural gas. Electric swap contracts through December 2016 are valued using the New York Independent System Operator ("NYISO") Swap Futures Closing Price as posted on NYMEX Clearport. The electric swap contracts from January 2017 through December 2019 are valued using NYISO forward prices provided by a broker, OTC Global Holdings, as posted on the SNL Financial website. All of the electric swap contracts have been classified as Level 3 assets in the fair value hierarchy, since Clearport uses unobservable inputs, such as bi-lateral contracts, projected activity and pricing data from major market participants in its determination of the futures closing price and OTC Global Holdings provides pricing from its forward power curve. Management believes these prices approximate fair value for these instruments. Generally, a change in any of the underlying assumptions would result in a positively correlated change in the fair value measurement. The credit risk considered in the fair value assessment of contracts in a liability position is that associated with Central Hudson. Based on Central Hudson's current senior unsecured debt ratings by Moody's, S&P and Fitch, management has concluded that the credit risk associated with Central Hudson's non-performance related to these instruments is not significant, and therefore, no adjustment was made to the fair value. For those contracts in an asset position, management believes the credit risk of non-performance by counterparties is not significant due to the fact that Central Hudson utilizes multiple counterparties, all of which have ratings by Moody's, S&P and Fitch, which denote expectations of a low default risk. Additionally, unrealized gains and losses on Central Hudson's derivative contracts have no impact on earnings. Based on the credit ratings by Moody's, S&P and Fitch of the counterparty, management has concluded that the credit risk associated with the counterparty's non-performance on call options in an asset position is not significant. Therefore, no adjustment related to credit risk has been made to the fair value of contracts in an asset position.

The Effect of Derivative Instruments on the Statements of Income

Realized gains and losses on Central Hudson's derivative instruments are conveyed to or recovered from customers through PSC authorized deferral accounting mechanisms, with no material impact on cash flows, results of operations or liquidity. Realized gains and losses on Central Hudson's energy derivative instruments are reported as part of purchased natural gas, purchased electricity and fuel used in electric generation in Central Hudson's and CH Energy Group's Statements of Income as the corresponding amounts are either recovered from or returned to customers through fuel cost adjustment clauses in revenues.

For the years ended December 31, 2015, 2014 and 2013, neither CH Energy Group nor Central Hudson had derivatives designated as hedging instruments. The following table summarizes the effects of CH Energy Group and Central Hudson derivatives on the Statements of Income (In Thousands):

	Amount of Gain Recognized as Increase in the Income Statement			
	Year Ended December 31,			
	2015	2014	2013	Location of Gain (Loss)
Central Hudson:				
Electricity swap contracts	$ (14,773)	$ 15,761	$ 2,571	Regulatory (asset)/liability(1)
Natural gas swap contracts	(2,536)	889	(325)	Regulatory (asset)/liability(1)
Total Central Hudson	$ (17,309)	$ 16,650	$ 2,246	
Griffith:				
Heating oil call option contracts	$ -	$ -	$ (8)	Discontinued operations
Total Griffith	$ -	$ -	$ (8)	
Total CH Energy Group	$ (17,309)	$ 16,650	$ 2,238	

(1) Realized gains and losses on Central Hudson's derivative instruments are conveyed to or recovered from customers through PSC authorized deferral accounting mechanisms, with an offset in revenue and on the balance sheet, and no impact on results of operations.

Other Hedging Activities

Griffith

Prior to the sale of Griffith on March 4, 2014, Griffith used weather derivative contracts to hedge the effect on earnings of significant variances in weather conditions from normal patterns, if such contracts can be obtained on reasonable terms. Weather derivative contracts are accounted for in accordance with guidance specific to accounting for weather derivatives. In the year ended December 31, 2014 approximately $1.3 million of expense was recorded to the income statement related to Griffith's weather derivatives. This amount was included in income from discontinued operations in the CH Energy Group Consolidated Statement of Income.

Central Hudson – Electric

On September 3, 2015, Central Hudson entered into a weather option for the period December 15, 2015 through March 15, 2016 to hedge the effect of significant variances in weather conditions on electricity costs. For Central Hudson, this impacts purchased electric expense and revenue, but does not have a net income impact due to the full deferral authority over commodity costs through its electric cost adjustment charge clause. The aggregate limit on the contract is $10 million. This contract will be accounted for in accordance with guidance specific to accounting for weather derivatives. The premium paid is being amortized to purchased electricity over the term of the contract and any payouts earned will be recorded as a reduction to purchased electricity in the Statement of Income. The unamortized balance of this contract at December 31, 2015 is $1.2 million and is currently included in the “special deposits and prepayments” line item of Central Hudson’s and CH Energy Group’s Balance Sheets. The fair value of the weather option as of December 31, 2015 based on third party marketer pricing for similar instruments approximates the unamortized balance. The third party marketer’s price is based on significant unobservable inputs, including short term temperature forecasts and historical temperature fluctuations in winter, and as such would be a Level 3 valuation.

Central Hudson – Gas

On September 4, 2015, Central Hudson entered into a weather option for the period December 1, 2015 through March 31, 2016 to hedge the effect of significant variances in weather conditions and price on natural gas costs. For Central Hudson, this impacts purchased natural gas expense and revenue, but does not have a net income impact due to the full deferral authority over commodity costs through its natural gas cost adjustment charge clause. The aggregate limit on the contract is $10 million. The terms of this contract include both a weather and gas price trigger. However, management believes weather is the predominant trigger for any payout that may be earned under the contract. Therefore, this contract will be accounted for in accordance with guidance specific to accounting for weather derivatives. The premium paid is being amortized to purchased gas over the term of the contract and any payouts earned will be recorded as a reduction to purchased gas in the Statement of Income. The unamortized balance of the option at December 31, 2015 is $1.3 million and is currently reflected in the “special deposits and prepayments” line item of Central Hudson’s and CH Energy Group’s Balance Sheets. The fair value of the weather option as of December 31, 2015 based on third party marketer pricing for similar instruments approximates the unamortized balance. The third party marketer’s price is based on an analysis which includes significant unobservable inputs, specifically short term weather forecasts, historical temperature fluctuations and correlation between daily temperature fluctuations and natural gas prices in winter, and as such would be a Level 3 valuation.

NOTE 15 – Other Fair Value Measurements

Other Assets Recorded at Fair Value

In addition to the derivatives reported at fair value discussed in Note 14 – "Accounting for Derivative Instruments and Hedging Activities", CH Energy Group and Central Hudson report certain other assets at fair value in the Consolidated Balance Sheets. The following table summarizes the amount reported at fair value related to these assets as of December 31, 2015 and 2014 (In Thousands):

	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
As of December 31, 2015:				
Other Investments	$ 8,847	$ 8,847	$ -	$ -
As of December 31, 2014:				
Other Investments	$ 4,317	$ 4,317	$ -	$ -

As of December 31, 2015 and 2014 a portion of the trust assets for the funding of SERP were invested in mutual funds and money market accounts, which are measured at fair value on a recurring basis. These investments are valued at quoted market prices in active markets and as such are Level 1 investments as defined in the fair value hierarchy. These amounts are included in the line titled "Other investments" within the Deferred Charges and Other Assets section of the CH Energy Group Consolidated and Central Hudson Balance Sheets.

In 2011, CHEC recorded an impairment loss for the full value of its investment in CH-Community Wind. An impairment analysis was performed and based on this analysis, the present value of the after-tax projected cash flows using a market participant's expected return, is insufficient for CHEC to recover any of its investment. This analysis used significant unobservable inputs including a discount rate and projected cash flows for the entity and as such this is a Level 3 investment. As of December 31, 2015, management believes the fair value of this investment remains at zero and is therefore appropriately reserved.

Other Fair Value Disclosure

Financial instruments are recorded at carrying value in the financial statements, however, the fair value of these instruments is disclosed below in accordance with current accounting guidance related to financial instruments.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash and Cash Equivalents: Carrying amount

Long-term Debt: Quoted market prices for the same or similar issues (Level 2)
Valuations were obtained for each issue using the observed Treasury market in conjunction with secondary market trading levels and recent new issuances of comparable companies.

Notes Payable: Carrying amount
Due to the short-term nature (typically one month or less) of Notes Payable borrowings, the carrying value is equivalent to the current fair market value.

Long-term Debt Maturities and Fair Value - CH Energy Group
(Dollars in Thousands)

	Fixed Rate		Variable Rate		Total Debt Outstanding	
Expected Maturity Date	Amount	Estimated Effective Interest Rate	Amount	Estimated Effective Interest Rate	Amount	Estimated Effective Interest Rate
As of December 31, 2015:						
2016	$ 9,315	3.36%	$ -	-%		
2017	34,406	6.13%	-	-%		
2018	31,503	2.67%	-	-%		
2019	28,607	5.21%	-	-%		
2020	17,718	4.57%	-	-%		
Thereafter	358,796	4.94%	63,700	0.70%		
Total	$ 480,345	4.88%	$ 63,700	0.70%	$ 544,045	4.40%
Fair Value	$ 527,750		$ 63,700		$ 591,450	
As of December 31, 2014:						
2015	$ 1,230	6.87%	$ -	-%		
2016	9,315	3.36%	-	-%		
2017	34,406	6.13%	-	-%		
2018	31,503	2.67%	-	-%		
2019	28,607	5.21%	-	-%		
Thereafter	356,514	5.05%	63,700	0.65%		
Total	$ 461,575	4.97%	$ 63,700	0.65%	$ 525,275	4.45%
Fair Value	$ 531,666		$ 63,700		$ 595,366	

Long-term Debt Maturities and Fair Value - Central Hudson
(Dollars in Thousands)

	Fixed Rate		Variable Rate		Total Debt Outstanding	
Expected Maturity Date	Amount	Estimated Effective Interest Rate	Amount	Estimated Effective Interest Rate	Amount	Estimated Effective Interest Rate
As of December 31, 2015:						
2016	$ 8,000	2.78%	$ -	-%		
2017	33,000	6.10%	-	-%		
2018	30,000	2.46%	-	-%		
2019	27,000	5.11%	-	-%		
2020	16,000	4.33%	-	-%		
Thereafter	348,250	4.88%	63,700	0.70%		
Total	$ 462,250	4.81%	$ 63,700	0.70%	$ 525,950	4.31%
Fair Value	$ 507,345		$ 63,700		$ 571,045	
As of December 31, 2014:						
2015	$ -	-%	$ -	-%		
2016	8,000	2.78%	-	-%		
2017	33,000	6.10%	-	-%		
2018	30,000	2.46%	-	-%		
2019	27,000	5.11%	-	-%		
Thereafter	344,250	4.98%	63,700	0.65%		
Total	$ 442,250	4.89%	$ 63,700	0.65%	$ 505,950	4.36%
Fair Value	$ 508,723		$ 63,700		$ 572,423	

NOTE 16 – Related Party Transactions

Thompson Hine LLP serves as outside counsel to CH Energy Group and Central Hudson. One partner in that firm serves as each corporation's General Counsel and Corporate Secretary. The following are legal fees paid by CH Energy Group and Central Hudson for the years ended December 31, 2015, 2014 and 2013. (In Thousands):

	Year Ended December 31, 2015	2014	2013
CH Energy Group	$ 1,347	$ 1,712	1,666
Central Hudson	$ 1,154	$ 1,461	880

CH Energy Group may provide general and administrative services ("services") to, and receive services from, Fortis, and other subsidiaries of Fortis. The costs of these services are reimbursed by the beneficiary company through accounts receivable and accounts payable, as necessary. CH Energy Group also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis or other affiliates. Central Hudson also provides services to, and receives services from, its parent company, CH Energy Group or other affiliates and incurs charges from CH Energy Group for the recovery of general corporate expenses incurred. Central Hudson also incurs charges directly with Fortis or other subsidiaries of Fortis. These transactions are in the normal course of business and are recorded at the United States exchange amounts. Related party transactions included in operating expenses and accounts receivable in the periods ended December 31, 2015, 2014 and 2013 are as follows (in Thousands):

Period Ending	December 31, 2015	December 31, 2014	December 31, 2013
CH Energy Group[(1)]	Fortis	Fortis	Fortis
Operating Expenses	$ 629	$ 575	$ 226
Accounts Receivable	$ 195	$ -	$ 151
Accounts Payable	$ -	$ 9	$ -

Period Ending	December 31, 2015			December 31, 2014			December 31, 2013		
Central Hudson[(1)]	CHEG	Fortis	Other Affiliates	CHEG	Fortis	Other Affiliates	CHEG	Fortis	Other Affiliates
Operating Expenses	$ 1,119	$ -	$ -	$ 980	$ -	$ -	$ 866	$ -	$ -
Accounts Receivable	$ 65	$ 195	$ 9	$ 69	$ 3	$ 15	$ 17	151	$ 489
Accounts Payable	$ 336	$ -	$ -	$ 299	$ -	$ -	$ 243	-	$ -

(1) Fortis amounts reported above include Fortis and all Fortis subsidiaries.

NOTE 17 – New Accounting Guidance

Newly adopted and soon to be adopted accounting guidance is summarized below, including explanations for any new guidance issued in 2015 (except that which is not currently applicable) and the expected impact on CH Energy Group and its subsidiaries.

Impact	Category	Accounting Reference	Title	Issued Date	Effective Date
1	Revenue from Contracts with Customers (Topic 606)	ASU No. 2014-09	Revenue from Contracts with Customers	May-14	Jan-18
1	Intangibles - Goodwill & Other, Internal Use Software (Topic 810)	ASU No. 2015-05	Customers Accounting for Fees Paid in a Cloud Computing Arrangement	Apr-15	Jan-16
2	Presentation of Financial Statements-Going Concern (Subtopic 205-40)	ASU No. 2014-15	Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern	Aug-14	Jan-16
2	Consolidation (Topic 810)	ASU No. 2015-02	Amendment to Consolidation Analysis	Feb-15	Jan-16
2	Inventory (Topic 330)	ASU No. 2015-11	Simplifying the Measurement of Inventory	Jul-15	Jan-17
2	Plan Accounting (Topics 960, 962 & 965)	ASU No. 2015-12	Amendments to Accounting Standards Codification, Investment Contracts (I), Investment Disclosures (II) and Measurement Date Practical Expedient (III)	Jul-15	Jan-16
3	Compensation-Stock Compensation (Topic 718)	ASU No. 2014-12	Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period	Jun-14	Jan-16
4	Interest - Imputation of Interest (Subtopic 835-30)	ASU No. 2015-15	Simplifying the Presentation of Debt Issuance Costs Associated with Line-of-Credit Arrangements	Aug-15	Aug-15
4	Derivatives & Hedging (Topic 815)	ASU No. 2015-13	Application Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets	Aug-15	Aug-15
5	Interest - Imputation of Interest (Subtopic 835-30)	ASU No. 2015-03	Simplifying the Presentation of Debt Issuance Costs	Apr-15	Jan-16
5	Classification of Deferred Taxes (Topic 740)	ASU No. 2015-17	Balance Sheet Classification of Deferred Taxes	Nov-15	Jan-17

Impact Key:

(1) CH Energy Group and its subsidiaries are assessing the impact, if any, that the adoption of this standard will have on the financial condition, results of operations and cash flows.

(2) No material impact on the financial condition, and no anticipated impact in the results of operations and cash flows of CH Energy Group and its subsidiaries upon future adoption.

(3) CH Energy Group and Central Hudson have adopted this ASU early. The impact resulting from the election of a CH Energy Group officer to resign under change in control agreements are reflected in the compensation expense related to performance share units in Note 11 - "Equity-Based Compensation."

(4) CH Energy Group and Central Hudson adopted this ASU on the effective date. No impact on the financial condition, results of operations and cash flows of CH Energy Group and its subsidiaries upon adoption.

(5) CH Energy Group and Central Hudson have adopted this ASU early. No material impact on the financial condition, results of operations and cash flows of CH Energy Group and its subsidiaries. Certain 2014 amounts have been reclassified to conform to 2015 presentation, see Note 1 "Summary of Significant Accounting Policies " for further details.

NOTE 18 – Subsequent Events

In addition to items disclosed in the footnotes, CH Energy Group has performed an evaluation of events subsequent to December 31, 2015 through the date the financial statements were issued and noted the following additional items to disclose.

On January 15, 2016, CH Energy Group's Board of Directors approved a $5.5 million dividend payment to parent FortisUS that was paid on January 28, 2016.

On January 21, 2016, under Case 15-E-0464, the PSC approved the petition filed on August 7, 2015 in which Central Hudson sought approval to defer for future recovery $5.284 million of incremental electric storm restoration expense plus carrying charges associated with the 2014 Thanksgiving Storm. Recovery of these costs will be postponed until the next rate filing.

On February 9, 2016, Standard & Poor's Ratings Services ("S&P") affirmed its ratings on Central Hudson, including the 'A' issuer credit rating and the 'A' senior unsecured debt rating, and revised the outlook to negative from stable. S&P based the negative outlook on Fortis's planned acquisition of ITC Holdings Corp.

MANAGEMENT'S DISCUSSION and ANALYSIS of FINANCIAL CONDITION and RESULTS of OPERATIONS

For the Year Ended December 31, 2015

This Management Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the 2015 Financial Statements and the notes thereto.

Company: CH Energy Group is the holding company parent corporation of three principal, wholly owned subsidiaries, Central Hudson Gas & Electric Corporation ("Central Hudson"), Central Hudson Electric Transmission LLC ("CHET") and Central Hudson Enterprises Corporation ("CHEC"). All of CH Energy Group's common stock is indirectly owned by Fortis Inc. ("Fortis"), which is the largest investor-owned gas and electric distribution utility in Canada. Central Hudson is a regulated electric and natural gas subsidiary. CHET holds CH Energy Group's ownership stake in New York Transco, LLC ("Transco"), a partnership formed to address transmission constraints in NY. CHEC, the parent company of CH Energy Group's non-regulated businesses and investments, had one wholly owned operating subsidiary during the first quarter of 2014, Griffith Energy Services, Inc. ("Griffith"). On March 4, 2014, CHEC completed the sale of Griffith, its previously 100% owned subsidiary, to Star Gas Partners, L.P.

Mission and Strategy

Mission

CH Energy Group's mission is to provide electricity and natural gas to an expanding customer base in a safe, reliable, courteous and affordable manner; to produce growing financial returns for shareholders; to foster a culture that encourages employees to reach their full potential; and to be a good corporate citizen.

CH Energy Group's strategy is to:

- Invest primarily in electric and gas transmission and distribution; and
- Maintain a financial profile that supports a credit rating for Central Hudson in the "A" category.

Strategy Execution

Management continues to focus on investment in Central Hudson's electric and natural gas infrastructure as the core of its strategy. Central Hudson invested approximately $141 million in 2015, and its five year forecast includes significantly increasing annual capital investments. The long-term capital program provides for continued strengthening of existing electric and gas infrastructure, expansion of gas distribution systems and investments in technologies that will improve reliability and customer satisfaction. Central Hudson has effectively managed its operational challenges, including significant weather events, in the past few years. However, primarily as a result of the extended rate freeze through June 2015 following the Fortis acquisition, Central Hudson did not achieve its allowed return in 2015. Effective July 1, 2015, Central Hudson received electric and gas delivery rate increases which provide the Company an opportunity to earn a 9% allowed return on equity.

As part of CH Energy Group's overall strategy to invest in electric transmission and distribution, CH Energy Group formed CHET to be an investor in Transco, a partnership with affiliates of the other investor owned utilities in New York (Con Edison, Orange & Rockland Utilities, National Grid, New York State Electric & Gas and Rochester Gas & Electric). Transco was created to develop, own and operate electric transmission projects in New York State. In December 2014, Transco filed an application with the Federal Energy Regulatory Commission ("FERC") for the recovery through a formula rate of Transco's cost and return on investment of five high voltage transmission projects totaling $1.7 billion ("Transco's Initial FERC Filing"). CHET's maximum commitment for these five projects is $182 million, which is the maximum budgeted amount for these projects at 100% equity. In November 2015, Transco filed an Offer of Partial Settlement with FERC ("Transco's Settlement"), resolving all issues set for hearing or pending in requests for rehearing in Transco's Initial FERC Filing. Two of the projects included in Transco's Initial FERC Filing (the "AC Projects") are not subject to the terms of the Transco Settlement and are held in abeyance. The total expected cost for the three projects included in the Settlement is approximately $241 million. Transco expects to receive a final decision from FERC during the first quarter 2016 and the New York State Public Service Commission ("PSC") regulatory approvals during the second quarter of 2016. The two AC Projects excluded from the Transco's Settlement are part of the AC Transmission Proceeding with the PSC. In December 2015, the PSC issued an Order to move forward in the review of the AC Projects with the New York State Independent System Operator ("NYISO"). As part of the Order, the PSC requested that one of Transco's projects be removed from the AC Transmission Proceeding. The total cost of this one project was approximately $250 million. Transco's remaining AC project is estimated to cost approximately $1.2 billion.

Central Hudson

Business Description and Strategy

Central Hudson is subject to regulation by the PSC. The Company's earnings are derived primarily from the revenue it generates from delivering energy to approximately 300,000 electric and 79,000 natural gas customers, with earnings growth coming primarily from increases in net utility plant. Central Hudson's delivery rates are designed to recover the cost of providing safe and reliable service while affording the opportunity to earn a fair and reasonable return on its capital.

Central Hudson's strategy is to provide exceptional value to its customers by:

- Practicing continuous improvement in everything we do;
- Investing in T&D infrastructure to enhance reliability, improve customer satisfaction and reduce risk;
- Moderating cost pressures that increase customer bill levels and commodity exposures that cause customer bill variability; and
- Advocating on behalf of customers and other stakeholders;
- Investing in employee development to meet the business needs of today and the future.

Opportunities and Risks

Central Hudson invests significant capital on an annual basis. Central Hudson's investments enhance safety and reliability through cost-beneficial solutions, which are intended to improve customer satisfaction and reduce risk. Opportunities to enhance transmission and distribution systems and information systems technologies are evaluated and prioritized based on their expected benefits, projected costs and estimated risks.

Central Hudson believes that there are continuing opportunities for further expansion of its current natural gas customer base due to natural gas' advantage as an economic, clean, and abundant fuel. Central Hudson began implementing a natural gas expansion strategy in 2013 and increased its natural gas customer base by more than 1,000 customers over the past two years. Management believes the increase in natural gas customers during 2016 will be in line with recent annual increases. Central Hudson will continue to seek financing alternatives through private lenders and the New York State Energy Research & Development Authority ("NYSERDA") in order to remove the cost barrier to customers converting to natural gas.

The key risks management sees in achieving its overall strategy are the regulatory environment, successful execution of its capital investment programs, customer bill pressures from significant capital investments and the economy in Central Hudson's service territory.

Central Hudson's ability to meet its financial objectives is largely dependent on supportive ratemaking practices by the PSC. Risks related to these practices include (1) reduced allowed returns on equity, (2) PSC allowed revenues that result in less than full recovery of the legitimate costs of providing service, resulting in earned returns below authorized returns, (3) declining PSC support for strong capital structures and credit ratings, (4) changes in deferral accounting that increase the volatility of earnings and/or defer cash recovery of our costs, (5) elimination of RDMs, and (6) changes in the mechanisms currently in place for recovery of Central Hudson's commodity purchases. Management believes Central Hudson's commitments to providing safe and reliable service, customer satisfaction, operational excellence and promoting positive customer and regulatory relations are important for supportive regulatory relationships and obtaining full cost recovery and competitive returns on invested capital.

The PSC Order Authorizing the Acquisition of CH Energy Group by Fortis provided an extension of the key provisions from the 2010 Rate Order, with a 2-year rate freeze through June 30, 2015 and setting aside $40 million of funds to benefit customers, primarily through offsets to regulatory assets in order to mitigate future rate increases. As a result of the 2-year rate freeze, Central Hudson did not earn a return on new capital investments in the utility of approximately $215 million and absorbed inflationary cost increases over this time period. Additionally, falling interest rates since the 2010 Rate Order led to a decrease in the authorized ROE in the 2015 Rate Order proceeding. A PSC Order establishing new rates became effective July 1, 2015.

The key provisions of the current rate plan include an authorized regulatory return on equity of 9.0% and a 48% regulatory equity ratio; the continuation of RDMs; full recovery and deferral provisions for purchased electric and gas, MGP site remediation, pension and OPEB expenses. The rate plan also contains service quality thresholds, performance below or above which entails financial penalties or incentives. For additional discussion of the key terms of the 2015 Rate Order, see Regulatory Proceedings – "2015 Rate Order".

During the second quarter of 2014, Governor Cuomo and the Public Service Commission announced the commencement of its Reforming the Energy Vision ("REV") proceeding. REV is an initiative that aims to improve the efficiency of the electric system; reduce emissions; encourage greater development of clean generation, fuel diversity and energy efficiency measures; and provide customers with knowledge and tools for effective management of their total energy use through the adoption of new technologies on both the utility and customer side of the meter. During the first quarter of 2015, the Commission issued the REV Track 1 “Order Adopting Regulatory Policy Framework and Implementation Plans”. The Order addresses the vision of the future for the industry, provides an overview of the Distributed System Platform Provider (“DSP”) and their role in integrated system planning, grid operations, and market operations; identifies and concludes that utilities will be required to serve as DSPs. Central Hudson expects to continue its efforts working with the other New York electric utilities and various stakeholders in the energy industry to develop policy positions in order to facilitate the implementation of REV.

During 2015 Central Hudson formed the Energy Transformation & Solutions Division to lead the company’s efforts associated with REV. The group’s first initiative is a web-based, energy services exchange providing information on energy management and access to third-party products and services. On Aug. 4, 2015, the PSC approved the online energy exchange, as one of seven statewide demonstration projects. It is expected to launch during the first half of 2016. Along with the online energy exchange, the Energy Transformation & Solutions Division is tasked with continuing the successful operation of the company’s energy efficiency efforts and initiating a territory wide Dynamic Load Management program and a Targeted Demand Response program. The goal of the Targeted Demand Response program is to reduce peak demand in specific areas, which will allow Central Hudson to defer the need for capital investments and produce savings for its customers.

The outcome of REV and the many related proceedings cannot be predicted at this time, but they could result in an increased or decreased scope of regulated activities, earnings potential, and risk.

Another risk is the ability to effectively manage costs, which is a key component of Central Hudson’s strategy. The continued implementation of Lean Six Sigma techniques – a data-driven approach to develop processes that are faster, higher quality and less costly – to streamline existing business processes and foster innovation will play critical roles in managing the costs of doing business in a sustainable manner.

The economy in Central Hudson’s service territory affects the growth of utility rate base and earnings through a direct relationship to customer additions and peak demand growth as well as affecting Central Hudson’s ability to collect receivables. Management believes the economy in Central Hudson’s service territory has good long-term growth prospects, but unexpected prolonged downturns could inhibit its ability to meet long-term business objectives. Central Hudson has an economic development program intended to increase job growth and income in its service territory.

CH Energy Group - Regulated Operations - Central Hudson
Financial Highlights
Period Ended December 31

	Year To Date		
	2015	**2014**	**Change**
Electricity Sales (GWh)	5,132	5,075	57
Natural Gas Sales (PJ)	23.5	23.0	0.5
($millions)			
Revenues	$ 690.9	$ 742.8	$ (51.9)
Energy Supply Costs	247.8	311.8	(64.0)
Other Operating Expenses	298.2	304.8	(6.6)
Depreciation and amortization	44.1	43.9	0.2
Other Income, net	6.1	5.4	0.7
Finance Charges	30.1	31.6	(1.5)
Income Taxes	31.1	22.4	8.7
Net income	$ 45.6	$ 33.8	$ 11.8

Earnings: Earnings for 2015 as compared to 2014 increased by $11.8 million, primarily driven by an increase in delivery rates effective July 1, 2015, per the 2015 Rate Order and a power generator who signed on as a new firm customer at the end of 2014. Effective July 1, 2015, in accordance with the 2015 Rate Order, revenues from this power generator are being deferred for future gas customer rate moderation. Year over year earnings were also favorably impacted by electric energy efficiency incentives earned during 2015 upon achieving certain targets established by the PSC for Central Hudson's internal programs and the recovery of a tax gross up billed to customers related to contributions in aid of construction ("CIAC") on projects not required under Central Hudson's tariff. These incremental amounts charged to customers are to cover tax payments, net of the depreciation benefits over the tax life of the project. Partially offsetting these favorable items was the impact of the rate freeze implemented in 2013 on the first six months of 2015, due to higher expenses without a corresponding increase in delivery rates.

The current year's revenue and energy supply costs reflect significantly lower commodity prices. This did not have a direct impact on earnings due to the full deferral of commodity costs and the RDM.

Electricity Sales & Natural Gas Sales: Year over year electricity sales were relatively unchanged. Natural gas sales were favorably impacted as a result of a colder winter heating season above and beyond a colder than normal first quarter of 2014. Also impacting year over year gas sales was higher volumes delivered to a power generator as a result of the higher operating run time of the facility. This increase was mitigated by decreased volumes in the fourth quarter of 2015 as a result of warmer than normal weather. These variations do not materially impact Central Hudson's revenue as a result of its RDM structure.

Depreciation and Amortization: The year over year increase is due to the investment in Central Hudson's electric and gas infrastructure in accordance with its capital expenditure program partially offset by the PSC-approved extension of the useful lives of certain utility plant, effective July 1, 2015 per the 2015 Rate Order. The net impact resulted in only a slight increase in depreciation expense year over year.

Other Income, net: Other income, net increased year over year primarily due to income recognized for the tax gross up billed to customers related to a CIAC on non-tariff projects, partially offset by losses on Central Hudson's deferred compensation assets.

Finance Charges: Finance charges (interest charges) decreased year over year primarily due to decreases in carryings charges on regulatory liabilities as a result of the offset of regulatory asset and liability balances resulting in the establishment of a net regulatory liability for future rate moderation in accordance with the 2015 Rate Order.

Corporate Taxes: Corporate taxes increased year over year primarily as a result of an increase in taxable income.

Central Hudson Revenues - Electric
Period Ended December 31

($millions)	Year to Date		
	2015	2014	Change
Revenues with Matching Expense Offsets:[1]			
Recovery of commodity purchases	$ 190.0	$ 228.2	$ (38.2)
Sales to others for resale	3.9	4.7	(0.8)
Other revenues with matching offsets	84.0	89.1	(5.1)
Subtotal	277.9	322.0	(44.1)
Revenues Impacting Earnings:			
Customer sales	257.6	241.6	16.0
RDM and other regulatory mechanisms	(1.3)	7.8	(9.1)
Energy efficiency incentives	2.0	-	2.0
Other revenues	8.1	8.4	(0.3)
Subtotal	266.4	257.8	8.6
Total Electric Revenues	$ 544.3	$ 579.8	$ (35.5)

(1) Revenues with matching offsets do not affect earnings since they offset related costs, the most significant being energy cost adjustment revenues, which provide for the recovery of purchased electricity costs. Other related costs include authorized business expenses recovered through rates and the cost of special programs authorized by the PSC and funded with certain available credits. Changes in revenues from electric sales to other entities for resale also do not affect earnings since any related profits or losses are returned or charged, respectively, to customers.

Central Hudson Revenues - Natural Gas
Period Ended December 31

($millions)	Year to Date		
	2015	2014	Change
Revenues with Matching Expense Offsets:[1]			
Recovery of commodity purchases	$ 40.4	$ 59.6	$ (19.2)
Sales to others for resale	13.6	18.8	(5.2)
Other revenues with matching offsets	13.6	18.3	(4.7)
Subtotal	67.6	96.7	(29.1)
Revenues Impacting Earnings:			
Customer sales	69.4	66.2	3.2
RDM and other regulatory mechanisms	1.8	(0.6)	2.4
Other revenues	7.8	0.7	7.1
Subtotal	79.0	66.3	12.7
Total Natural Gas Revenues	$ 146.6	$ 163.0	$ (16.4)

(1) Revenues with matching offsets do not affect earnings since they offset related costs, the most significant being energy cost adjustment revenues, which provide for the recovery of purchased natural gas costs. Other related costs include authorized business expenses recovered through rates and the cost of special programs authorized by the PSC and funded with certain available credits. For natural gas sales to other entities for resale, 85% of such profits are returned to customers.

Central Hudson's revenues consist of two major categories: those that offset specific expenses in the current period (matching revenues), and those that impact earnings. Matching revenues recover Central Hudson's actual costs for particular expenses (most notably, purchased electricity and purchased natural gas, pensions and OPEBs, the NYS Temporary State Assessment, and NYS energy efficiency programs). Any difference between these revenues and the actual expenses incurred is deferred for future recovery from or refund to customers and therefore does not impact earnings, with the exception of related carrying charges which are recorded within income or interest charges in the CH Energy Group and Central Hudson Statement of Income.

Electric Revenue: The year over year decrease in electric revenue was primarily driven by the significantly lower wholesale prices for commodity purchases partially offset by the recovery of previously deferred purchased electricity costs. Additionally impacting year over year revenues was an increase in customer delivery rates beginning July 1, 2015, as approved in the 2015 Rate Order.

Gas Revenue: The year over year decrease in gas revenue is primarily due to a decrease in wholesale natural gas prices, which had a significant impact in the first quarter of 2015. This impacted both the revenue recovered by Central Hudson for commodity purchases as well as revenues generated from natural gas sales for resale. These decreases were partially offset by higher gas revenues in the first six months of 2015 as a result of a power generator who signed on as a new firm gas customer at the end of 2014 and an increase in customer delivery rates beginning July 1, 2015, as approved in the 2015 Rate Order.

Central Hudson Operating Expenses
Period Ended December 31

($millions)	Year To Date		
	2015	**2014**	**Change**
Expenses Currently Matched to Revenues:[(1)]			
Purchased electricity	$ 193.9	$ 232.9	$ (39.0)
Purchased natural gas	54.0	78.4	(24.4)
Pension & OPEB	20.3	27.3	(7.0)
NYS energy programs	42.3	40.8	1.5
Other matched expenses	32.1	41.2	(9.1)
Subtotal	342.6	420.6	(78.0)
Other Operating Expense Variations:			
Tree trimming	14.4	15.0	(0.6)
Property and school taxes[(2)]	42.5	39.8	2.7
Weather related service restoration	3.6	5.6	(2.0)
Distribution Maintenance	11.5	9.3	2.2
Uncollectible accounts and reserve	7.6	6.6	1.0
Depreciation and amortization	44.1	43.9	0.2
Other expenses	123.8	119.7	4.1
Subtotal	247.5	239.8	7.7
Total Operating Expenses	$ 590.1	$ 660.4	$ (70.3)

(1) Includes expenses that, in accordance with the 2013 Joint Proposal and the 2015 Rate Order, are adjusted in the current period to equal the revenues earned for the applicable expenses and the differences are deferred.
(2) In accordance with the 2013 Joint Proposal and the 2015 Rate Order, Central Hudson is authorized to defer for the benefit of or recovery from customers 90% of any difference between actual property tax expense and the amounts provided in rates for each Rate Year. Central Hudson's portion is limited to 10%, with a maximum of approximately $0.8 million per Rate Year.

Operating Expenses: Operating expenses decreased year over year primarily as a result of the lower commodity prices, partially offset by the recovery of previously purchased electric costs. Variations in purchased gas and electricity costs do not have a direct impact on earnings due to Central Hudson's regulatory mechanism for the full deferral of commodity costs. Partially offsetting the decrease in commodity costs is an increase in Other Operating Expenses as detailed in the above chart. Through June 30, 2015, these increases did not have a corresponding increase in revenues due to the continuing effect of the rate freeze implemented in 2013. Rates increased on July 1, 2015 as authorized in the 2015 Rate Order, covering higher operating expenses, primarily consisting of higher property taxes.

CH Energy Group - Non-regulated and Holding Company Operations Financial Highlights

Period Ended December 31

	Year To Date		
($millions)	**2015**	**2014**	**Change**
Loss from Continuing Operations	(1.8)	(7.2)	5.4
Income from Discontinued Operations	-	7.7	(7.7)

Loss from Continuing Operations: The year over year decrease in losses is a result of the election by two CH Energy Group officers to resign under Change in Control agreements in 2014.

Income from Discontinued Operations: Income from discontinued operations was $7.7 million lower in 2015 compared to the prior year because 2014 included a $4.7 million, net of tax, gain on the sale of Griffith, which closed on March 4, 2014, as well as earnings from Griffith operations through the sale date.

Financial Position

The following table outlines the significant changes in the Balance Sheet of Central Hudson as of December 31, 2015 and December 31, 2014:

CH Energy Group – Regulated – Central Hudson
Significant Changes in the Balance Sheets
as of December 31, 2015 and December 31, 2014
($millions)

Balance Sheet Account	Increase (Decrease)	Explanation
Accounts Receivable	(13.2)	Decrease primarily the result of the warmer weather in late 2015, along with lower commodity prices, resulting in lower customer bills.
Accrued unbilled utility revenues	11.4	Increase primarily due to the authorization granted in the 2015 Rate Order to record and defer the residual unbilled electric revenues greater than the 30 day estimate previously allowed.
Regulatory assets - Current	(25.1)	Decrease due to the recovery of previously deferred commodity costs as well as the decrease in RDMs as a result of actual electric revenues greater than target.
Income tax receivable	22.5	Increase in income tax receivable driven by an overpayment of estimated taxes prior to the passage of bonus depreciation legislation in December 2015.
Regulatory assets - related to pension plan costs	(10.0)	Decrease primarily due to the amortization of net periodic costs partially offset by the offset of a portion of deferred pension costs in accordance with the 2015 Rate Order.
Regulatory assets - long term	(55.5)	Decrease primarily due to the offset of certain regulatory assets against certain regulatory liabilities in the establishment of the net regulatory liability to be used for rate moderation in accordance with the 2015 Rate Order and a decrease in deferred and accrued MGP costs related to the Kingston MGP site.
Other investments	5.9	Increase primarily due to funding of the non-qualified Supplemental Executive Retirement Plan.
Long term debt, net of current maturities	20.0	Increase due to the issuance of long-term debt in March 2015.
Notes payable - current	27.0	Increase due to the issuance of short term debt for working capital requirements.
Regulatory liabilities - current	31.2	Increase primarily due to the offset of certain regulatory assets and liabilities in the establishment of the net regulatory liability to be used for rate moderation in the next twelve months and a new deferral established for residual unbilled electric revenues per the 2015 Rate Order.
Other liabilities - current	(7.4)	Decrease primarily due to the payment of previously accrued costs related to energy efficiency programs.
Regulatory liabilities - long term	(28.3)	Decrease primarily due to the offset of rate base impact of repair project and carrying charges related to the OPEB reserve per the 2015 Rate Order.
Regulatory liabilities- related to OPEB costs	(25.6)	Decrease primarily due to the offset of a portion of OPEB costs in accordance with the 2015 Rate Order partially offset by the amortization of net periodic costs.
Accrued environmental remediation costs- LT	(14.8)	Decrease primarily due to reduction of the accrual for estimated costs associated with remediation at the Kingston MGP site as a result of proposals received and tentative contract with successful bidder.
Accrued pension costs	(18.6)	Decrease primarily due to $21.3M in pension contributions in 2015.
Accumulated deferred income tax	20.1	The increase in accumulated deferred income tax is driven by the passage of bonus depreciation legislation in December 2015.

Liquidity And Capital Resources

The following table outlines the summary of cash flow:

CH Energy Group - Regulated, Non-regulated and Holding Company Summary of Cash Flow
Period Ended December 31,

($millions)	Year to Date			
		2015		2014
Cash, beginning of period	$	22.6	$	18.1
Operating Activities		104.3		87.6
Investing Activities		(144.9)		(16.2)
Financing Activities		31.6		(66.9)
Cash, end of period	$	13.6	$	22.6
Dividends paid on Common Stock - CH Energy Group	$	(22.0)	$	(75.0)
Dividends paid to parent - Central Hudson	$	(24.5)	$	(5.0)

Operating Activities: Operating activities generated more cash in 2015 primarily due to lower working capital requirements as a result of lower wholesale energy, as well as a tax refund associated with bonus depreciation legislation passed at the end of 2014.

Investing Activities: Cash provided by investing activities was lower in 2015 primarily due to the proceeds from the sale of Griffith in 2014; an increase in capital expenditures for Central Hudson's electric and gas transmission and distribution systems; and funding of the Supplemental Executive Retirement Plan ("SERP") in 2015 under the terms of the SERP Trust Agreement.

Financing Activities: Financing activities provided more cash in 2015 primarily due to lower dividends paid in 2015 as compared to 2014 when the dividends paid reflected proceeds from the Griffith sale. There were also lower long-term debt borrowings in 2015 for capital expenditures, working capital and general corporate purposes at Central Hudson, compared to 2014 where proceeds from long-term debt borrowings were used in part to redeem expiring long-term debt. In addition, there was an infusion of capital by Fortis and short-term borrowings in 2015.

Anticipated Sources and Uses of Cash

CH Energy Group's cash flow is primarily generated by the operations of its utility subsidiary, Central Hudson. Generally, the subsidiary does not accumulate significant amounts of cash but rather provides cash to CH Energy Group in the form of dividends.

Central Hudson expects to fund capital expenditures with cash from operations and a combination of short-term and long-term borrowings. Central Hudson may alter its plan for capital expenditures as its business needs require.

Central Hudson intends to fund growth in its long-lived assets in a manner that maintains an equity ratio no less than 48%, excluding short-term debt balances. Central Hudson plans to utilize short-term debt to fund seasonal and temporary variations in working capital requirements. If wholesale energy prices increase, Central Hudson would expect a corresponding increase in its current level of working capital.

CH Energy Group believes cash generated from operations and funds obtained from its financing program will be sufficient in 2016 and the foreseeable future to meet working capital needs, pay dividends on its Common Stock, and fund investments to fulfill CHET's investment in Transco and Central Hudson's public service obligations and growth objectives.

CH Energy Group's secondary sources of funds are its cash reserves and its credit facilities. CH Energy Group's ability to use its credit facility is contingent upon maintaining certain financial covenants. CH Energy Group does not anticipate that those covenants will restrict its access to funds in 2016 or the foreseeable future.

Committed Credit Facilities

Committed Credit Facilities for CH Energy Group and Central Hudson at December 31, 2015
($millions)

		December 31, 2015		
	Credit Limit	Outstanding	Available	Maturity
CH Energy Group (unregulated)	$ 50	$ -	$ 50	July 10, 2020
Central Hudson (regulated)	200	12	188	October 15, 2020
Total	$ 250	$ 12	$ 238	

CH Energy Group is well positioned with a strong balance sheet and strong liquidity.

On July 10, 2015, CH Energy Group entered into a third amended and restated credit agreement with four commercial banks. The credit commitment of the banks under the agreement is $50 million, a reduction from the previous $100 million credit agreement, reflecting Energy Group's lower liquidity needs following the divestiture of Griffith.

By Order issued and effective September 18, 2015, the PSC authorized the increase in Central Hudson's committed credit to $200 million. On October 15, 2015, Central Hudson entered into a new credit agreement with six commercial banks, replacing the existing credit agreement. The credit commitment of the banks was increased by $50 million to $200 million, bringing the consolidated CH Energy Group committed credit back to a total of $250 million.

Uncommitted Credit

Central Hudson has uncommitted short-term credit arrangements with two commercial banks totaling $25 million. At December 31, 2015, $13 million was outstanding. In addition, at December 31, 2015, Central Hudson had an intercompany short-term borrowing of $2 million from CH Energy Group.

Central Hudson's Bond Ratings

	December 31, 2015		December 31, 2014	
	Rating[1]	Outlook	Rating[1]	Outlook
S&P	A	Stable	A	Stable
Moody's	A2	Stable	A2	Stable
Fitch	A-	Stable	A	Negative

On July 1, 2014, Fitch Ratings affirmed the rating on Central Hudson's senior unsecured debt and revised the rating outlook to negative from stable. The negative outlook reflected Fitch's expected weakening of credit metrics due to Central Hudson's two-year rate freeze, the expiration of bonus depreciation and the impact of rising capital expenditures. On July 2, 2015, Fitch downgraded the rating on Central Hudson's senior unsecured debt to A- from A and revised the rating outlook to stable from negative. The rating downgrade reflects Fitch's expectation of the impact of persistently elevated capital expenditures and deferral of the recovery of manufactured gas plant site remediation costs on Central Hudson's financial profile.

On February 9, 2016, Standard & Poor's Ratings Services ("S&P") affirmed its ratings on Central Hudson, including the 'A' issuer credit rating and the 'A' senior unsecured debt rating, and revised the outlook to negative from stable. S&P based the negative outlook on Fortis's planned acquisition of ITC Holdings Corp.

Central Hudson's strong investment-grade credit ratings help facilitate access to long-term debt; however, management can make no assurance regarding the availability of financing or its terms and costs.

[1] These senior unsecured debt ratings reflect only the views of the rating agency issuing the rating, are not recommendations to buy, sell, or hold securities of Central Hudson and may be subject to revision or withdrawal at any time by the rating agency issuing the rating. Each rating should be evaluated independently of any other rating.

CH Energy Group's capital structure follows:

CH Energy Group's Capital Structure

	December 31, 2015		December 31, 2014	
	$millions	%	$millions	%
Long-term Debt	$ 544.1	48.4	$ 525.3	50.1
Short-term Debt	25.0	2.2	-	-
Common Equity	555.4	49.4	524.0	49.9
Total	$ 1,124.5	100.0	$ 1,049.3	100.0

Central Hudson's Capital Structure

	December 31, 2015		December 31, 2014	
	$millions	%	$millions	%
Long-term Debt	$ 525.9	47.4	$ 506.0	48.6
Short-term Debt	27.0	2.4	-	-
Common Equity	557.2	50.2	536.1	51.4
Total	$ 1,110.1	100.0	$ 1,042.1	100.0

Central Hudson's customer rates reflect a capital structure - excluding short-term debt - with 48% common equity. Central Hudson is currently managing its financing to maintain its common equity at no less than 48%. Central Hudson may change its long term capitalization targets to match the capital structure reflected in future customer rates.

In March 2015, Central Hudson issued $20 million of 10-year Series F notes with an interest rate of 2.98% per annum. Central Hudson used the proceeds from the sale of the notes for capital expenditures, working capital and general corporate purposes.

Central Hudson meets its need for long-term debt financing through privately placed debt. As a regulated electric and natural gas utility company, Central Hudson is required to obtain authorization from the PSC to issue securities with maturities greater than 12 months. For further discussion, refer to the "Financing Petition" section under "Regulatory Proceedings".

CH Energy Group and Central Hudson believe they will be able to meet their short-term and long-term cash requirements, assuming that Central Hudson's future rate plans reflect the costs of service, including a reasonable return on invested capital.

Contractual Obligations

A review of capital resources and liquidity should also consider other contractual obligations and commitments, which are further disclosed in Note 12 – "Commitments and Contingencies."

Regulatory Proceedings

2015 Rate Order

On June 17, 2015, the Public Service Commission ("PSC") issued an Order Approving Rate Plan ("Rate Order") in Cases 14-E-0318 and 14-G-0319. The Rate Order adopted the terms set forth in the April 22, 2015 Joint Proposal. The Rate Order became effective July 1, 2015, with Rate Year 1 ("RY1"), Rate Year 2 ("RY2") and Rate Year 3 ("RY3") defined as the twelve months ending June 30, 2016, June 30, 2017 and June 30, 2018, respectively.

Key provisions of the Rate Order include:

- Electric delivery rate increases of $15.3 million, $16.0 million and $14.1 million in RY1, RY2 and RY3, respectively

- Gas delivery rate increases of $1.8 million, $4.6 million and $4.4 million RY1, RY2 and RY3, respectively

- To mitigate customer bill impacts from the delivery rate increases, the Company will utilize available regulatory liabilities as electric bill credits of $13.0 million in Rate Year 1, $12.0 million in Rate Year 2, and $2.0 million in Rate Year 3; and gas bill credits of $2.548 million in Rate Year 1 and $1.7 million in Rate Year 2. In addition, to the extent that the Company receives gas delivery revenues from the Danskammer Generating Station ("Danskammer") in Rate Year 1, 50% of those revenues will be refunded via a bill credit to the Company's gas customers in Rate Year 2. Similarly, 50% of the gas delivery revenues received from Danskammer in Rate Year 2 will be refunded via a bill credit to the Company's gas customers in Rate Year 3. The remaining amounts will accrue carrying charges and be available to offset future rate increases.

- The Company's electric and gas revenue requirements reflect a common equity ratio of 48% and a return on equity ("ROE") of 9.0%.

- Earnings above 9.5% and up to 10.0% will be shared 50% / 50% between the shareholder and ratepayers. Earnings above 10.0% and up to 10.5% will be shared 20% / 80% between the shareholder and ratepayers. Earnings above 10.5% will be shared 10% / 90% between the shareholder and ratepayers.

- The Rate Order includes the establishment of a major storm reserve for electric operations, with related deferral provisions, and provides $0.7 million each rate year as funding for the reserve.

- The Rate Order provides for partial or full reconciliation of certain expenses including, but not limited to: property taxes, pensions/OPEBs, environmental site investigation and remediation costs, variable and fixed rate debt, and stray voltage. In addition, the Rate Order includes downward-only reconciliations for net plant, distribution and transmission right-of-way maintenance costs, security costs and rate case expenses. The Rate Order also authorizes a continuation of full cost recovery of electric and natural gas commodity costs.

- Central Hudson will continue its revenue decoupling mechanisms ("RDMs") for its electric and gas businesses. The structure and provisions of the RDMs will generally continue per Central Hudson's 2010 Rate Order except that the provisions for annual and interim RDM periods will be replaced with provisions for semi-annual RDM periods.

- Central Hudson's Customer Service Quality Performance Mechanism (consisting of the PSC Annual Compliant Rate, the Customer Satisfaction Index and Appointments Kept measures) and associated reporting requirements will continue in accordance with the PSC's Order issued on June 26, 2013 in Case 12-M-0192. The Company will be subject to a negative revenue adjustment if it fails to meet any metric as set forth in the Order.

- To reduce service terminations, the PSC authorized an annual incentive in the form of a 5 basis point positive revenue adjustment for each Rate Year in which the Company reduces service terminations to residential customers in occupied buildings below 11,000.

- The Rate Order modifies the electric reliability and gas safety performance measures, which generally hold the Company to more stringent standards and to a higher performance than those measures currently in place.

- The Rate Order directs Central Hudson to replace or eliminate 13 miles of leak prone pipe in calendar year 2016, 14 miles in 2017, and 15 miles in 2018. In the event the Company fails to meet its leak prone pipe target in any calendar year, the Company will be subject to an 8 basis point negative revenue adjustment. The Rate Order provides the Company with an incentive to surpass its leak prone pipe target by providing for a positive revenue adjustment for each mile replaced or eliminated in excess of the applicable target, capped at maximum of 5 miles for a total 10 basis points per calendar year, which the Company will defer for future recovery.

- The Rate Order directs the Company to transition to monthly billing for all customers from its current bi-monthly billing of certain customer classes by July 2016.

- The Rate Order provides $1 million annual program funding each Rate Year to provide additional incentives and support for customer conversion to gas. Central Hudson will receive an annual incentive in the form of 1 basis point for every 200 gas customers added above the combined total customer count forecast for residential and commercial customers for each Rate Year.

- The Rate Order provides for Network Strategy and Distribution Automation capital expenditures. Full implementation of the Network Strategy and Distribution Automation project beyond Rate Year 1 would be dependent upon PSC agreement that the Company remains on track for the successful demonstration of the functional capability and operation/integration of these investments.

- The Rate Order reflects removal of energy efficiency funds (both electric and gas) from base delivery rates and recovers utility-run energy efficiency budgets via a surcharge mechanism. The internal labor component associated with energy efficiency portfolio budgets is included in base rates to facilitate integrating the administrative function of energy efficiency into base rates.

Reforming the Energy Vision Order

On July 1, 2015, Central Hudson filed its REV Demonstration Project Report with the PSC Staff ("Staff") seeking to develop and implement a Behind the Meter Services REV Demonstration Project. This project provides market participants with a transactional platform where they can discuss available products, search for competitive providers, and offers the providers access to customers. The Company also filed a petition with the PSC seeking approval for a Community Solar REV Demonstration project. This project is a 2MW facility that will provide access to solar market energy for those customers that may otherwise not be able to install a photo voltaic facility at their site. Energy produced by the community solar facility will be offered to customers at a fixed price for a period of 25 years. The community solar project will increase customer choice and engagement, reduce carbon emissions and provide local benefits, such as job creation and an increased tax base. On July 1, 2015, the Staff issued its Benefit-Cost Analysis ("BCA") Framework White Paper, and on July 28, 2015 Staff issued its White Paper on ratemaking and utility business models. Comments on Staff's BCA paper were filed August 21, 2015 and Reply Comments were filed on September 10, 2015. On October 15, 2015, the Staff issued its "Distributed System Implementation Plan Guidance". Comments on Staff's proposal were filed on January 6, 2016.

Risk Assessment and Remediation of NYS Gas Facilities Order

In February 2014, the PSC issued an order requiring risk assessments and remediation of certain NYS gas facilities to identify conditions similar to those found in connection with a natural gas explosion that occurred in Horseheads, New York in 2011. Management currently believes these costs will qualify for deferral treatment. In May 2014, the PSC issued a modifying Order extending the requirement for utilities to complete risk assessments until February 2015 and also included a requirement effective August 2014 for utilities to report to Staff on the progress of their risk assessments every 45 days. Further, in response to requests filed by the utilities, on February 19, 2015 the PSC issued a notice extending the deadline to submit risk assessment to September 30, 2015. Central Hudson filed its risk assessment and risk mitigation plan with the PSC on September 1, 2015.

No prediction can be made regarding the outcome of this matter or the potential impacts on Central Hudson at this time.

Petition of Central Hudson Gas & Electric Corporation for PSC Approval and Recovery of Deferred Incremental Costs Associated with the PSC's Multiple Orders Requiring Risk Assessment and Remediation of New York Gas Facilities in Case 11-G-0565 (Cases 09-G-0589 and 12-M-0192)

On October 14, 2015, Central Hudson filed a petition with the PSC seeking approval for future recovery of $2.115 million of deferred incremental costs associated with new compliance and reporting requirements to assess the risks of its underground gas facilities, along with related carrying incurred during the twelve month ended June 30, 2015, pursuant to a series of PSC Orders issued in Case 11-G-0565. Authority to defer the incremental expenses associated with the revised definition of the BES was provided under Section V.A3 (Governmental Actions) in the Joint Proposal (Case 09-E-0588) and extended for two additional rates years to June 30, 2015 in accordance with the Acquisition Order issued and effective in Case 12-M-0192 on June 26, 2013. Section V.A3 authorized Central Hudson to defer the revenue requirement effect of subsequent legislative, governmental, PSC and other regulatory actions that individually had material consequences for any element of costs, with carrying charges, at the pre tax rate of return ("PTROR"). The Company believes the incremental costs associated with these new compliance requirements meet the PSC's criteria for deferral based on the following: 1) amount is incremental to the amount in rates; 2) the incremental amount is material (2% of net income available to common by department) and extraordinary in nature; and 3) the utility's earnings are below the authorized rate of return on common equity.

No prediction can be made regarding the outcome of this matter or the potential impacts on Central Hudson at this time.

Petition of Central Hudson Gas & Electric Corporation for PSC Approval of Deferred Incremental Costs Associated with 2014 Thanksgiving "SnowBird" Storm
(Case 15-E-0464)
On August 7, 2015, Central Hudson filed a petition with the PSC seeking approval for future recovery of $5.284 million of incremental electric storm restoration expense plus carrying charges incurred during the twelve months ended June 30, 2015, which is the third rate year established by the PSC in its approved Joint Proposal (Case 09-E-0588). These incremental costs represent the amount Central Hudson deferred on its books as of June 30, 2015 based on actual costs incurred, bills received and an estimate for bills outstanding. The Company believes the incremental costs associated with this storm meet the PSC's criteria for deferral based on the following: 1) amount is incremental to the amount in rates; 2) the incremental amount is material and extraordinary in nature; and 3) the utility's earnings are below the authorized rate of return on common equity. On January 21, 2016, the PSC approved the deferral of incremental storm restoration costs together with carrying charges at the allowed pre-tax rate of return. Recovery of these costs is postponed until the next rate filing.

Petition of Central Hudson Gas & Electric Corporation for PSC Approval for Recovery of Deferred Incremental Costs Associated with New Compliance Requirements Resulting from NERC's Changes to the Bulk Electric System
(Cases 09-E-0588 and 12-M-0192)
On September 1, 2015, Central Hudson filed a petition with the PSC seeking approval for future recovery of $1.054 million of incremental costs, including internal labor and related carrying charges associated with new compliance requirements established by the North American Electric Reliability Corporation ("NERC") on its revised definition of the Bulk Electric System ("BES") as approved by FERC. These incremental costs were above the authorized rate allowance for the twelve months ended June 30, 2015 and represent the amount Central Hudson deferred on its books based on actual costs incurred. Authority to defer the incremental expenses associated with the revised definition of the BES was provided under Section V.A3 (Governmental Actions) in the Joint Proposal (Case 09-E-0588) and extended for two additional rates years to June 30, 2015 in accordance with the Acquisition Order issued and effective in Case 12-M-0192 on June 26, 2013. Section V.A3 authorized Central Hudson to defer the revenue requirement effect of subsequent legislative, governmental, PSC and other regulatory actions that individually had material consequences for any element of costs, with carrying charges, at the pre tax rate of return ("PTROR"). The Company believes the incremental costs associated with these new compliance requirements meet the PSC's criteria for deferral based on the following: 1) amount is incremental to the amount in rates; 2) the incremental amount is material (2% of net income available to common by department) and extraordinary in nature; and 3) the utility's earnings are below the authorized rate of return on common equity.

Potential Impacts: No prediction can be made regarding the final outcome of this matter.

Natural Gas Plastic Fusion Practices Proceeding
In June 2014, the PSC instituted this proceeding focused on compliance by local distribution gas companies ("LDCs") with the tracking, testing, qualifying and requalifying procedures of persons who have performed plastic fusions on natural gas facilities, as required by NYCRR Part 255. The proceeding is intended to gather information that will assist the PSC in deciding what steps, if any, will be taken to address any lapses by LDCs in their qualification and requalification procedures. On April 2, 2015, the PSC issued a Memorandum and Resolution Adopting Gas Safety Regulation Amendments that mirror the language of the PSC's gas safety regulations with their corollary federal regulations. The revisions to NYCRR Part 255 that were adopted pertain to definition of gas "service line"; leakage survey requirements to expanded areas affected by the new definition of "service line"; the elimination of the option of solely soap testing small sections of gas pipe before placing pipe into service; the elimination of operators' option to throttle gas pressure in a delivery line once every five years to maintain their current Maximum Allowable Operating Pressure and the removal of the odorization exception for gas being transported to storage. LDCs are expected to come into compliance immediately with all the newly adopted rules except the new definition of "service line" for which implementation requirements are still pending further PSC action. The PSC will commence a proceeding to continue to work with stakeholders to implement survey and inspection requirements in a reasonable manner that maintains safety standards.

No prediction can be made regarding the outcome of this matter or the potential impacts to Central Hudson at this time.

Financing Petition
On April 30, 2015, Central Hudson filed a petition with the PSC (Case 15-M-0251) seeking approval to: (a) enter into multi-year committed credit agreements to provide committed funding to meet expected liquidity needs in amounts not to exceed $200 million in the aggregate and with maturities not to exceed five years and (b) issue and sell long-term debt from time to time through December 31, 2018, in an amount not to exceed $350 million in the aggregate.

A higher level of committed credit would provide greater liquidity to support construction forecasts, known seasonality, volatile energy markets, adverse borrowing environments, and other unforeseen events. The approval to issue and sell $350 million of long-term debt will support Central Hudson's financing of its construction expenditures, refund maturing long-term debt, potentially refinance $33.7 million of multi-modal long-term NYSERDA bonds, and refinance up to $30 million of other securities if economic and appropriate.

On September 18, 2015, the PSC issued its Order Authorizing Issuance of Securities for Central Hudson in this proceeding. The Order grants the authorization requested for $200 million of committed credit; grants the authorization requested, with conditions, for $350 million of long-term debt; and revokes the authorization granted in the prior financing order, avoiding the overlap in orders (the prior financing order covered a period ending December 31, 2015 and the new order is effective immediately).

Gas Energy Efficiency Programs
On June 19, 2015, the PSC issued an Order authorizing Gas Energy Efficiency programs and their implementation for 2016 in Case 15-M-0252 and adopted budgets and targets for 2016. The electric 2016 targets and budgets had been included in the PSC's REV Track 1 Order and are the same as the 2015 targets and budgets. The recovery (excluding labor) will be through a new Energy Efficiency Tracker, effective January 1st 2016.

Management Audit Implementation Plan
In 2015, Central Hudson completed implementation of all recommendations set forth in Case 09-M-0764 as directed in the PSC's May 20, 2011 Order.

AC Transmission Proceeding
On December 17, 2015, the PSC issued its Order "Finding Transmission Needs Driven by Public Policy Requirements" in the AC Transmission Proceeding for two new 345 kV major electric transmission facility segments to cross Central East and UPNY/SENY. These interfaces will provide additional transmission capacity to move power from upstate to downstate. This Order advances a competitive process managed by the New York Independent System Operator ("NYISO") for soliciting and reviewing proposed solicitations. These solicitations have the potential to be selected as transmission developers and will allow the cost recovery for their development and construction costs from the beneficiaries of the transmission upgrades through the NYISO tariff mechanism regulated by FERC. The Order establishes evaluation criteria and specific analysis for the NYISO to utilize in its review of solutions to satisfy identified transmission needs. The Order also directed that proposals for all other transmission routes filed during the proceeding, be withdrawn.

No prediction can be made regarding the outcome of this matter or the potential impacts to Central Hudson at this time.

Net Metering
On October 16, 2015, the PSC issued an Order in Case 15-E-0407 eliminating the 6% ceiling on net metering and instituted floating ceilings for utilities pending a determination of appropriate rate design for net metering which will be determined in a separate proceeding. On December 23, 2015, the PSC instituted a new proceeding, Case 15-E-0751"In the Matter of the Value of Distributed Energy Resources".

No prediction can be made regarding the outcome of this matter or the potential impacts to Central Hudson at this time.

Other Regulatory Proceedings
On December 11, 2015, the PSC issued an Order Extending Clean Energy Programs authorizing the New York State Energy Research and Development Authority to continue to operate the Energy Efficiency Portfolio Standard (EEPS), Renewable Portfolio Standard (RPS) and Customer-Sited Tier programs through February 29, 2016.

Risk Factors

<u>Storms and other events beyond the Companies' control:</u> In order to conduct its business, Central Hudson must have access to natural gas and electric supplies and be able to utilize its electric and natural gas infrastructure. Any one or more of the following could impact the company's ability to access supplies and/or utilize critical facilities: (1) storms, natural disasters, wars, terrorist acts, cyber incidents, failure of critical equipment and other catastrophic events occurring both within and outside the service territory (2) third-party facility owner or supplier financial distress, (3) unfavorable governmental actions or judicial orders, and (4) bulk power system and gas transmission pipeline system capacity constraints.

Potential Impacts: The Company could experience service disruptions leading to lower earnings and/or reduced cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies and regulated rate recovery.

<u>Recovery of costs through rates:</u> Central Hudson's retail rates generally may not be changed during their respective terms, absent an increase that meets the PSC's requirements for deferral accounting. Examples of costs that may not be fully recovered include: (1) higher expenses than reflected in current rates, (2) penalties for failing to achieve performance metrics or violation of PSC Orders, (3) higher capital project costs, and (4) a determination by the PSC that the cost to place a project in service is above a level which is deemed prudent.

Potential Impacts: Central Hudson could have lower earnings and/or reduced cash flows if cost management and/or regulatory relief are not sufficient to alleviate the higher costs.

<u>Asbestos litigation and Manufactured Gas Plant facilities (MGP):</u> Litigation has been commenced by third parties against Central Hudson arising from the use of asbestos at certain of its previously owned electric generating stations. Central Hudson is also involved in a number of matters arising from contamination at former MGP sites.

Potential Impacts: To the extent not covered by insurance or recovered through rates, remediation costs, court decisions and settlements could reduce earnings and cash flows.

FORWARD-LOOKING STATEMENTS

Statements included in this annual report, which are not historical in nature, are intended to be "forward-looking statements." Forward-looking statements may be identified by words such as "anticipates," "intends," "estimates," "believes," "projects," "expects," "plans," "assumes," "seeks," and other similar words and expressions. CH Energy Group is subject to risks and uncertainties that could cause actual results to differ materially from those indicated in the forward-looking statements. The risks and uncertainties include, but are not limited to: deviations from normal seasonal temperatures and storm activity, changes in energy and commodity prices, availability of energy supplies, changes in interest rates, poor operating performance, legislative and regulatory developments, the outcome of litigations, and the resolution of current and future environmental issues. Additional information concerning risks and uncertainties may be found in the Management Discussion & Analysis section of CH Energy Group's quarterly and annual financial reports. These reports are available in the Financial Information section of website of CH Energy Group, at www.CHEnergyGroup.com. CH Energy Group undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events, or otherwise.

ANNUAL FINANCIAL REPORT SUPPLEMENT

Holding Company Regulation

CH Energy Group is a “holding company” under Public Utility Holding Company Act of 2005 (“PUHCA 2005”) because of its ownership interests in Central Hudson and CHEC. CH Energy Group, however, is exempt from regulation as a holding company under PUHCA 2005, because it derives substantially all of its public utility company revenues from business conducted within a single state, the State of New York. At the present time, CH Energy Group cannot predict whether and when its circumstances may change such that it no longer qualifies for exemption from PUHCA 2005.

Central Hudson

Central Hudson is a New York State natural gas and electric corporation formed in 1926. Central Hudson purchases, sells at wholesale and retail, and distributes electricity and natural gas at retail in portions of New York State. Central Hudson also generates a small portion of its electricity requirements.

Central Hudson serves a territory comprising approximately 2,600 square miles 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. The number of Central Hudson employees at December 31, 2015, was 966.

Central Hudson’s territory reflects a diversified economy, including manufacturing industries, governmental agencies, public and private institutions, wholesale and retail trade operations, research firms, farms and resorts.

Regulation
Central Hudson is subject to regulation as follows:

- <u>PSC</u> – services rendered (including the rates charged), major transmission facility siting, accounting treatment of certain items, and issuance of securities. For certain restrictions imposed by the Settlement Agreement, see Note 3 – “Regulatory Matters” of the Company’s 2015 Annual Report.

- <u>FERC</u> (under the Federal Power Act) – accounting and the acquisition and disposition of property.

- <u>North American Electric Reliability Corporation</u> – ownership, operation and use of a bulk power system.

- <u>DEC</u> – ownership, operation and use of hydroelectric facilities

Central Hudson is not subject to the Natural Gas Act and its hydroelectric facilities are not required to be licensed under the Federal Power Act.

Rates

<u>PSC</u> – Costs of service, both for electric and gas delivery service and supply costs, are recovered from customers through PSC approved tariffs, subject to a standard of prudency. For further information, see Note 1 – "Summary of Significant Accounting Policies" under the caption "Rates, Revenues and Cost Adjustment Clauses" and Note 3 – "Regulatory Matters" under the caption "2013 Joint Petition/2015 Rate Order" of the Company's 2015 Annual Report.

- <u>Customer classes</u> – Residential and non-residential.
- <u>Retail electricity services</u> – Various service classifications covering delivery service and full service (which includes electricity supply).
- <u>Retail natural gas services</u> – Various service classifications covering transport, retail access service, and full service (which includes natural gas supply).
- <u>RDMs</u> – Central Hudson's rates have included RDMs which are intended to minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented by breaking the link between energy sales and utility revenues and profits. Central Hudson's RDMs allow the Company to recognize electric delivery revenues and gas sales per customer at the levels approved in rates for most of Central Hudson's electric and gas customer classes.
- <u>Commodity costs</u> – 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.

<u>FERC</u> – Transmission rates and rates for electricity sold for resale which involve interstate commerce.

During 2015, the average price of electricity for full service customers was 16.36 cents per kWh as compared to an average of 17.58 cents per kWh in 2014. The average delivery price in 2015 was 6.36 cents per kWh and 6.21 cents per kWh in 2014. The increase in delivery price was primarily due to the return of base delivery revenue in order to meet the regulatory target and a reduction in the pass back of revenue realized from the revenue sharing agreement with one of the Company's former generating plants.

During 2015, the average price of natural gas for full-service customers was $12.64 per Mcf as compared to an average of $14.90 per Mcf in 2014. The average delivery price for natural gas for retail and full service in 2015 was $5.98 per Mcf and $6.13 per Mcf in 2014. The decrease in delivery price was primarily due to the refund of base delivery revenue in excess of the regulatory target.

Cost Adjustment Clauses and RDMs: For information regarding Central Hudson's electric and natural gas cost adjustment clauses and RDMs, see Note 1 – "Summary of Significant Accounting Policies" under the caption "Rates, Revenues and Cost Adjustment Clauses."

Electric

Central Hudson owns hydroelectric and gas turbine generating facilities as described below.

Type of Electric Generating Plant	Year Placed in Service/Refurbished	MW[1] Net Capability
Hydroelectric (3 stations)	1920-1986	22.4
Gas turbine (2 stations)	1969-1970	42.5
Total		64.9

(1) Reflects the name plate rating of Central Hudson's electric generating plants and therefore does not include firm purchases or sales.

Central Hudson owns substations having an aggregate transformer capacity of 5.4 million kilovolt amperes. Central Hudson's electric transmission system consists of 602 pole miles of line. The electric distribution system consists of approximately 7,200 pole miles of overhead lines and 1,500 trench miles of underground lines, as well as customer service lines and meters.

Electric Load and Capacity

Central Hudson's maximum one-hour demand for electricity within its own territory for the year ended December 31, 2015, occurred on July 29, 2015, and amounted to 1059 MW. Central Hudson's highest peak electric demand reached 1,295 MW on August 2, 2006. Central Hudson's current maximum one-hour demand for electricity within its own territory for the 2015-2016 winter capability occurred on January 4, 2016, and amounted to 829 MW.

Central Hudson owns minimal generating capacity and relies on purchased capacity and energy from third-party providers to meet the demands of its full service customers. For more information, see Note 12 – "Commitments and Contingencies."

Natural Gas

Central Hudson's natural gas system consists of 165 miles of transmission pipelines and 1,248 miles of distribution pipelines, as well as customer service lines and meters. For the year ended December 31, 2015, the total amount of natural gas purchased by Central Hudson from all sources was 11,159,501 Mcf.

The peak daily demand for natural gas of Central Hudson's customers for the year ended December 31, 2015, occurred on February 19, 2015 and amounted to 128,386 Mcf which is also Central Hudson's all-time highest winter period daily peak. Peak demand for the 2015-2016 heating season occurred on January 5, 2016 and was 115,470 Mcfs. Central Hudson's firm peak day natural gas capability in 2015-2016 heating season was 133,491Mcf.

Purchased Power and Generation Costs

For the year ended December 31, 2015, the sources and related costs of purchased electricity and electric generation for Central Hudson were as follows (In Thousands):

Sources of Energy	Aggregate Percentage of Energy Requirements		Costs in 2015
Purchased Electricity	98.1	%	$ 173,989
Hydroelectric and Other	1.9		38
Deferred Electricity Cost			19,893
Total	100.0	%	$ 193,920

Other Central Hudson Matters

Labor Relations: Central Hudson has an agreement with Local 320 of the International Brotherhood of Electrical Workers for its 566 unionized employees, representing construction and maintenance employees, customer service representatives, service workers, and clerical employees (excluding persons in managerial, professional, or supervisory positions). This agreement remains effective through April 30, 2017.

Property Additions: During the three-year period ended December 31, 2015, Central Hudson made gross property additions of $351.1 million and property retirements and adjustments of $58.4 million, resulting in a net increase (including construction work in progress) in gross utility plant of $292.7 million, or 18%.

Environmental Quality Regulation

Central Hudson is subject to regulation by federal, state, and local authorities with respect to the environmental effects of their operations. Environmental matters may expose Central Hudson to potential liability, which, in certain instances, may be imposed without regard to fault or may be premised on historical activities that were lawful at the time they occurred.

Central Hudson monitors its activities in order to determine their impact on the environment and to comply with applicable environmental laws and regulations.

The principal environmental areas relevant to Central Hudson (air, water and industrial and hazardous wastes) are described below. Unless otherwise noted, all required permits and certifications have been obtained by the applicable company. Management believes that the company was in material compliance with these permits and certifications during 2015. For further discussions related to environmental matters see Note 12 – “Commitments and Contingencies”.

Air Quality

The Clean Air Act Amendments of 1990 address attainment and maintenance of national air quality standards and impact Central Hudson electric generating facilities in South Cairo and Coxsackie, NY.

Water Quality

The Clean Water Act established the basic framework for federal and state regulation of water pollution control and requires facilities that discharge waste or storm water into the waters of the United States to obtain permits. Central Hudson has permits regulating pollutant discharges for relevant locations.

Industrial & Hazardous Substances and Wastes

Central Hudson is subject to federal, state and local laws and regulations relating to the use, handling, storage, treatment, transportation, and disposal of industrial, hazardous, and toxic wastes. See Note 12 − "Commitments and Contingencies" under the caption "Environmental Matters" for additional discussion regarding, among other things, Central Hudson's former MGP facilities and Little Britain Road.

Environmental Expenditures

2015 actual and 2016 estimated expenditures attributable in whole or in substantial part to environmental considerations are detailed in the table below (In Millions):

	2015	2016
Central Hudson	$ 2.9	$ 23.6

The increase in 2016 estimated expenditures relates primarily to MGP remediation activities at the Kingston and Eltings Corners sites. For further discussion of these activities, see Note 12 – "Commitments and Contingencies" under caption "Site Investigation and Remediation Program".

Central Hudson is also subject to regulation with respect to other environmental matters, such as noise levels, protection of vegetation and wildlife, and limitations on land use, and is in compliance with regulations in these areas.

Regarding environmental matters, except as described in Note 12 - "Commitments and Contingencies" under the caption "Environmental Matters," neither CH Energy Group nor Central Hudson are involved as defendants in any material litigation, administrative proceeding, or investigation and, to the best of their knowledge, no such matters are threatened against any of them.