Exhibit D

Balance sheets and income statements for each applicant

**FORTIS INC.**

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2015 and 2014

Prepared in accordance with accounting principles generally accepted in the United States

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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

# Fortis Inc.
## Consolidated Balance Sheets
### As at December 31
(in millions of Canadian dollars)

| | **2015** | 2014 |
|---|---|---|
| | | (Note 36) |
| **ASSETS** | | |
| **Current assets** | | |
| 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**

# Fortis Inc.
## Consolidated Statements of Earnings
### 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

# Fortis Inc.
## Consolidated Statements of Comprehensive Income
### 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

# Fortis Inc.
## Consolidated Statements of Cash Flows
## 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

# Fortis Inc.

## Consolidated Statements of Changes in Equity

### For the years ended December 31, 2015 and 2014

(in millions of Canadian dollars)

| | Common Shares (Note 18) | Preference Shares (Note 20) | Additional Paid-in Capital | Accumulated Other Comprehensive Income (Loss) (Note 21) | Retained Earnings | Non-Controlling Interests (Note 22) | Total Equity |
|---|---|---|---|---|---|---|---|
| **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

## 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.

## 1. DESCRIPTION OF THE BUSINESS (cont'd)

### 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.

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").

## 1. DESCRIPTION OF THE BUSINESS (cont'd)

### NON-REGULATED - FORTIS GENERATION (cont'd)

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).

## 2. NATURE OF REGULATION (cont'd)

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.

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.

## 2. NATURE OF REGULATION (cont'd)

*FortisBC Energy and FortisBC Electric (cont'd)*
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.

## 2. NATURE OF REGULATION (cont'd)

*FortisAlberta (cont'd)*
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.

## 2. NATURE OF REGULATION (cont'd)

*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.

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

### 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.

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

### Utility Capital Assets (cont'd)

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).

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

### Utility Capital Assets (cont'd)

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%).

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.

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

### 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 |

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

### Intangible Assets (cont'd)

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.

### 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.

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

### Goodwill (cont'd)

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.

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

### Employee Future Benefits (cont'd)

*Defined Benefit and Defined Contribution Pension Plans (cont'd)*
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.

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

### Employee Future Benefits (cont'd)

*Other Post-Employment Benefits Plans (cont'd)*
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.

### 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).

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

### Foreign Currency Translation (cont'd)

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.

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

### Derivative Instruments and Hedging Activities (cont'd)

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.

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

### Income Taxes (cont'd)

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, 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.

### 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).

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

### 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.

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

### 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.

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

### New Accounting Policies (cont'd)

*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).

### 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** *($ 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** *($ 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.

## 6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS (cont'd)

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 | |
| | | | |
| **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 | |

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

### 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).

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

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

*(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.

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

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

*(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.

*(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.

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

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

*(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 a 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).

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

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

*(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).

## 9. OTHER ASSETS (cont'd)

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).

## 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 |

## 10. UTILITY CAPITAL ASSETS (cont'd)

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** |

| | 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** | | 2,014 |
|---|---|---|---|---|
| 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 |

## 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.

## 15. LONG-TERM DEBT (cont'd)

**Regulated Utilities (cont'd)**
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).

## 16. CAPITAL LEASE AND FINANCE OBLIGATIONS (cont'd)

### UNS Energy (cont'd)

*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.

### 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)*).

## 16. CAPITAL LEASE AND FINANCE OBLIGATIONS (cont'd)

### 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 |

## 17. OTHER LIABILITIES (cont'd)

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).

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.

## 20. PREFERENCE SHARES (cont'd)

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.

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 for 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.

| *(in millions)* | 2015 Opening balance January | 2015 Net change | 2015 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 | 2014 Net change | 2014 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.

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

## 23. STOCK-BASED COMPENSATION PLANS (cont'd)

### Stock Options (cont'd)

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.

## 23. STOCK-BASED COMPENSATION PLANS (cont'd)

### Directors' DSU Plan (cont'd)

| 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%.

## 23. STOCK-BASED COMPENSATION PLANS (cont'd)

### PSU Plans (cont'd)

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.

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** |

## 23. STOCK-BASED COMPENSATION PLANS (cont'd)

### RSU Plans (cont'd)

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.

### 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.

## 26. INCOME TAXES (cont'd)

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.

## 26. INCOME TAXES (cont'd)

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.

## 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 |

## 27. EMPLOYEE FUTURE BENEFITS (cont'd)

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).

## 27. EMPLOYEE FUTURE BENEFITS (cont'd)

The following table summarizes the employee future benefit assets and liabilities and their classifications on the consolidated balance sheet.

| | Defined Benefit Pension Plans | | OPEB Plans | |
|---|---|---|---|---|
| *(in millions)* | **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 |

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 |

## 27. EMPLOYEE FUTURE BENEFITS (cont'd)

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.

## 27. EMPLOYEE FUTURE BENEFITS (cont'd)

| **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).

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).

## 29. BUSINESS ACQUISITIONS (cont'd)

### 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** |

## 29. BUSINESS ACQUISITIONS (cont'd)

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.

## 31. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

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.

## 31. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

### 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.

## 31. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

### Derivative Instruments (cont'd)

*Cash Flow Hedges (cont'd)*
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 (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:

| **Asset (Liability)** | **As at December 31, 2015** | | December 31, 2014 | |
|---|---|---|---|---|
| *(in millions)* | **Carrying Value** | **Estimated Fair** | 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.

## 31. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

### Financial Instruments Not Carried At Fair Value (cont'd)

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.

## 32. FINANCIAL RISK MANAGEMENT (cont'd)

### 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%).

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.

## 32. FINANCIAL RISK MANAGEMENT (cont'd)

### Liquidity Risk (cont'd)

*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) |

## 32. FINANCIAL RISK MANAGEMENT (cont'd)

### Liquidity Risk (cont'd)

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 |

(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.

## 33. COMMITMENTS (cont'd)

*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.

## 33. COMMITMENTS (cont'd)

(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 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.

## 34. CONTINGENCIES (cont'd)

**UNS Energy (cont'd)**

*Springerville Unit 1 (cont'd)*

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)*).

## 34. CONTINGENCIES (cont'd)

**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)*).

*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 Improvement Act*. The closing of the Acquisition is expected to occur in late 2016.

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

The financing of the Acquisition has been structured to allow Fortis to maintain investment-grade credit ratings and is consistent with the Corporation's existing capital structure. Financing of the cash portion of the Acquisition will be achieved primarily through the issuance of approximately US$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. In addition, Fortis has obtained commitments of US$2.0 billion from Goldman Sachs Bank USA to bridge the long-term debt financing and US$1.7 billion from The Bank of Nova Scotia to primarily bridge the sale of the minority investment in ITC. These non-revolving term credit facilities are repayable in full on the first anniversary of their advance 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).

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# ITC HOLDINGS CORP.

## FORM 8-K
(Current report filing)

Filed 02/25/16 for the Period Ending 02/25/16

| | |
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| Industry | Electric Utilities |
| Sector | Utilities |
| Fiscal Year | 12/31 |

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# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, DC 20549**

# FORM 8-K

**CURRENT REPORT**
**Pursuant to Section 13 or 15(d) of the**
**Securities Exchange Act of 1934**

Date of Report (Date of earliest event reported): **February 25, 2016**

# ITC HOLDINGS CORP.
(Exact Name of Registrant as Specified in its Charter)

Commission File Number: **001-32576**

| **Michigan** | **32-0058047** |
|---|---|
| (State of Incorporation) | (IRS Employer Identification No.) |

**27175 Energy Way, Novi, Michigan 48377**
(Address of principal executive offices) (zip code)

**(248) 946-3000**
(Registrant's telephone number, including area code)

**Not Applicable**
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

**Item 2.02 Results of Operations and Financial Condition.**

On February 25, 2016, ITC Holdings Corp. (the "Company") issued a press release disclosing its financial results as of and for the fourth quarter and full year ended December 31, 2015. The Company also announced that it updated its capital investment plan for its regulated operating companies for the period 2016 to 2018. The release is attached hereto as Exhibit 99.1 .

**Item 9.01 Financial Statements and Exhibits.**

**(d) Exhibits.**

99.1 ITC Holdings Corp. Press Release dated February 25, 2016.

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

February 25, 2016

ITC HOLDINGS CORP.

| | |
|---|---|
| By: | /s/ Christine Mason Soneral |
| | Christine Mason Soneral |
| Its: | Senior Vice President and General Counsel |

Exhibit 99.1

**ITC Reports Fourth Quarter and Year Ended 2015 Results**

**Highlights**

- *Full-year 2015 operating earnings of $2.08 per diluted common share; full-year 2015 reported earnings of $1.56 per diluted common share*
- *Fourth quarter 2015 operating earnings of $0.57 per diluted common share; fourth quarter 2015 reported earnings of $0.24 per diluted common share*
- *Full-year 2015 capital investments of $771.4 million*
- *Updated regulated operating company capital investment forecast to approximately $2.1 billion from $1.9 billion for 2016 through 2018*
- *Announced acquisition of ITC by Fortis Inc. on February 9, 2016 valued at US$11.3 billion, including ITC consolidated debt, concluding the board's evaluation of strategic alternatives*

| | Three months ended December 31, | | Twelve months ended December 31, | |
|---|---|---|---|---|
| (in thousands, except per share data) | 2015 | 2014 | 2015 | 2014 |
| **OPERATING REVENUES** | $ 224,034 | $ 231,097 | $ 1,044,768 | $ 1,023,048 |
| **REPORTED NET INCOME** | $ 37,365 | $ 46,738 | $ 242,406 | $ 244,083 |
| **OPERATING EARNINGS** | $ 87,592 | $ 75,913 | $ 323,806 | $ 292,039 |
| **REPORTED DILUTED EPS** | $ 0.24 | $ 0.30 | $ 1.56 | $ 1.54 |
| **OPERATING DILUTED EPS** | $ 0.57 | $ 0.48 | $ 2.08 | $ 1.85 |

**NOVI, Mich., February 25, 2016 -** ITC Holdings Corp. (NYSE: ITC) announced today its results for the fourth quarter and year ended December 31, 2015.

Reported net income for the fourth quarter, measured in accordance with Generally Accepted Accounting Principles (GAAP), was $37.4 million, or $0.24 per diluted common share, compared to $46.7 million or $0.30 per diluted common share for the fourth quarter of 2014. For the year ended December 31, 2015, reported net income was $242.4 million, or $1.56 per diluted common share, compared to $244.1 million, or $1.54 per diluted common share for the same period last year.

Operating earnings for the fourth quarter were $87.6 million, or $0.57 per diluted common share, compared to operating earnings of $75.9 million, or $0.48 per diluted common share for the fourth quarter of 2014. For the year ended December 31, 2015, operating earnings were $323.8 million, or $2.08 per diluted common share, compared to operating earnings of $292.0 million, or $1.85 per diluted common share for the same period last year.

ITC invested $771.4 million in capital projects at its operating companies during the year ended December 31, 2015, including $189.6 million at ITC *Transmission* , $174.8 million at METC, $388.4 million at ITC Midwest, $14.4 million at ITC Great Plains and $4.2 million of Development.

"I am very pleased to report that 2015 was another year of strong operational and financial performance," said Joseph L. Welch, chairman, president and CEO of ITC. "We delivered on our commitments to shareholders and customers while positioning ourselves for continued success in the long-term."

"We are pleased with our recent announcement that ITC has agreed to be acquired by Fortis Inc. We believe that Fortis is the ideal partner to provide a broad platform for ITC to make long-term strategic investments in electric transmission to the benefit of customers and stakeholders in support of ITC's mission to modernize electrical infrastructure in the United States," said Joseph L. Welch, chairman, president and CEO of ITC.

**Operating Earnings**

Operating earnings are non-GAAP measures that exclude the impact of after-tax expenses associated with the following items:

1. Regulatory charges of approximately $0.6 million for the fourth quarter of 2015. These expenses totaled $7.3 million, or $0.04 per diluted common share for the year ended December 31, 2015 and $0.1 million for the year ended December 31, 2014. Of the 2015 charges, $1.1 million relates to management's decision to write-off abandoned project costs at ITC *Transmission* and $6.2 million relates to a refund liability attributable to contributions in aid of construction (CIAC refund liability). The 2014 charge relates to certain acquisition accounting adjustments for ITC Midwest, ITC *Transmission* , and METC resulting from the Federal Energy Regulatory Commission (FERC) audit order on ITC Midwest issued in May 2012.
2. Loss on extinguishment of debt associated with the cash tender offer and consent solicitation transaction for select bonds at ITC Holdings that we completed in the second quarter of 2014. The impact of this item totaled $0.2 million for the fourth quarter of 2014 and $18.2 million, or $0.12 per diluted common share, for the year ended December 31, 2014.
3. Estimated refund liability associated with the Midcontinent ISO (MISO) regional base ROE rate (the base ROE) of $48.6 million, or $0.32 per diluted common share, for the fourth quarter of 2015 and $73.2 million, or $0.47 per diluted common share, for the year ended December 31, 2015 (of the $48.6 million estimated refund liability charge in the fourth quarter of 2015, $36.8 million, or $0.24 per diluted common share, relates to revisions to the estimated liability for periods prior to October 1, 2015, and of the $73.2 million estimated refund liability charge for the year ended December 31, 2015, $28.4 million, or $0.18 per diluted common share, relates to revisions to the estimated liability for periods prior to January 1, 2015). The ROE refund liabilities totaled $28.9 million, or $0.18 per diluted common share, for the fourth quarter and year ended December 31, 2014. The refund liability reflects the estimated refund obligation associated with the base ROE rate 206 complaints.
4. 2015 review of strategic alternatives transaction expenses of approximately $1.0 million, or $0.01 per diluted common share, for the fourth quarter and year ended December 31, 2015. Entergy Corporation transaction expenses incurred in the fourth quarter and year

ended December 31, 2014 were approximately $0.1 million and $0.7 million, or $0.01 per diluted common share, respectively.

Operating earnings for the fourth quarter and for the year ended December 31, 2015 increased by $11.7 million, or $0.09 per diluted common share, and $31.8 million, or $0.23 per diluted common share, compared with the same periods last year. The increases compared to the prior period were largely attributable to higher income associated with increased rate base at our operating companies, partially offset by non-recoverable bonus payments expensed primarily in the first quarter associated with completion of the Kansas V-Plan Project at ITC Great Plains in December of 2014 coupled with higher professional services for various development initiatives. Absent the Kansas V-Plan Project bonus payments, year-over-year operating earnings would have increased by approximately 15%.

**Share Repurchase**

On September 30, 2015, ITC Holdings entered into an accelerated share repurchase agreement (ASR) for $115.0 million, under the board of directors' authorization in April 2014. Under the ASR, ITC Holdings received an initial delivery of 2.8 million shares on October 1, 2015, with a fair market value of $92.0 million. The ASR was settled on November 5, 2015 and ITC Holdings received an additional 0.8 million shares as determined by the volume-weighted average share price of $32.57 including the agreed upon discount. The ASR's settlement in November 2015 marks the conclusion of the board-authorized share repurchase plan of up to $250 million in aggregate.

**Review of Strategic Alternatives**

On February 9, 2016, Fortis Inc. (Fortis), certain subsidiaries of Fortis, and 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 at the time of announcement. This brings to a close the board's review of strategic alternatives. ITC shareholders will receive US$22.57 in cash and 0.7520 of a Fortis common share per ITC share. Upon completion of the Acquisition, ITC will become a subsidiary of Fortis and approximately 27% of the shares of Fortis will be held by ITC shareholders. Fortis will apply to list its shares on the New York Stock Exchange in connection with the Acquisition and will continue to have its shares listed on the Toronto Stock Exchange. In addition to the necessary state approvals, the closing of the Acquisition is subject to both ITC and Fortis shareholder approvals, the satisfaction of other customary closing conditions, and certain Federal and State regulatory approvals including, among others, those of the FERC, the Committee on Foreign Investment in the United States, and the United States Federal Trade Commission/Department of Justice under the Hart-Scott-Rodino Antitrust Improvement Act. The closing of the Acquisition is expected to occur in late 2016.

**Capital Investment Plan**

ITC is updating its regulated operating company capital investment plan for the period of 2016 to 2018 to reflect approximately $2.1 billion of aggregate capital investments over this period. The capital investment plan is projected to increase ITC's average rate base plus construction work in progress (CWIP) balances from approximately $5.3 billion at the end of 2015 to approximately $6.6 billion at the end of 2018. This increase in average rate base plus CWIP is expected to result in compound annual growth in earnings per share greater than 10% percent over this period.

**Fourth Quarter 2015 Operating Earnings Financial Results Detail — Non-GAAP Measure**

ITC's operating revenues for the fourth quarter of 2015 increased to $301.2 million compared to $278.0 million for the fourth quarter of 2014. Amounts reported for the fourth quarter of 2015 exclude approximately $76.3 million in reduced pre-tax revenues associated with the MISO regional base ROE rate refund liability, which include $58.5 million related to adjustments to prior periods associated with the refund liability, and $0.9 million in reduced pre-tax revenues associated with the CIAC refund liability. Amounts reported for the fourth quarter of 2014 exclude approximately $46.9 million in reduced pre-tax revenues associated with the MISO regional base ROE rate refund liability. This increase was primarily due to higher revenue requirements attributable to a higher rate base at our regulated operating subsidiaries, as well as an increase in regional cost sharing revenues resulting from additional capital projects being placed in-service that have been identified by MISO as eligible for regional cost sharing.

Operation and maintenance (O&M) expenses of $24.8 million were $7.1 million lower than the same period in 2014. The decrease in O&M was primarily due to lower vegetation management requirements for the quarter.

General and administrative (G&A) expenses of $36.2 million were $8.3 million higher compared to the same period in 2014. Amounts reported for the fourth quarter 2015 exclude approximately $1.7 million of pre-tax expenses related to the review of strategic alternatives announced by the board on November 30, 2015 and concluded on February 9, 2016. The increase in G&A was primarily due to higher compensation expenses related to personnel additions and higher professional services for various development initiatives.

Depreciation and amortization expenses of $37.8 million increased by $4.4 million compared to the same period in 2014 due to a higher depreciable base resulting from property, plant and equipment additions.

Taxes other than income taxes of $20.7 million were $1.6 million higher than the same period in 2014. This increase was due to 2014 capital additions at our regulated operating subsidiaries, which are included in the assessment for 2015 property taxes.

Interest expense of $50.0 million increased by $2.8 million compared to the same period in 2014. Amounts reported for the fourth quarter 2015 and 2014 exclude pre-tax expenses related to the adjustments to operating earnings of $3.7 million and $0.9 million, respectively. The increase was due primarily to higher borrowing levels to finance capital investments.

The effective income tax rate for the fourth quarter of 2015 was 37.3 percent compared to 39.0 percent for the same period last year. Amounts reported for the fourth quarter of 2015 and 2014 exclude approximately $32.4 million and $18.8 million, respectively, associated with adjustments to operating earnings.

**Year End 2015 Operating Earnings Financial Results Detail — Non-GAAP Measure**

ITC's operating revenues for the year ended December 31, 2015 increased to $1,169.4 million compared to $1,070.0 million from the same period last year. Amounts reported for the year ended December 31, 2015 exclude approximately $115.1 million in reduced pre-tax revenues associated with the MISO regional base ROE rate refund liability, which include $45.8 million related to adjustments to prior periods associated with the refund liability, and $9.5 million in pre-tax revenues associated with the CIAC refund liability. Amounts reported for the year ended

December 31, 2014 exclude approximately $46.9 million in reduced pre-tax revenues associated with the MISO regional base ROE rate refund liability. This increase was primarily due to higher revenue requirements attributable to higher rate base at our regulated operating subsidiaries, as well as an increase in regional cost sharing revenues due to additional capital projects being placed in-service that have been identified by MISO as eligible for regional cost sharing.

O&M expenses of $113.1 million were $1.5 million higher for the year ended December 31, 2015 compared to the same period in 2014. The increase in O&M expenses was primarily due to higher expenses associated with transmission system monitoring and control activities.

G&A expenses of $141.8 million were $27.9 million higher compared to the same period in 2014. Amounts reported for the year ended December 31, 2015 exclude pre-tax expenses of approximately $1.4 million related to regulatory charges and $1.7 million related to the review of strategic alternatives announced by the board on November 30, 2015 and concluded on February 9, 2016. Amounts reported for the year ended December 31, 2014 exclude approximately $1.1 million of pre-tax expenses associated with the Entergy transaction. The increase in G&A expenses was primarily due to incentive-based compensation for bonus payments associated with completion of the Kansas V-Plan Project at ITC Great Plains in December 2014 and higher professional services for various development initiatives.

Depreciation and amortization expenses of $144.7 million increased by $16.7 million for the year ended December 31, 2015 compared to the same period in 2014 primarily due to a higher depreciable base resulting from property, plant and equipment additions.

Taxes other than income taxes of $82.4 million were $5.9 million higher compared to the same period in 2014. This increase was due to 2014 capital additions at our regulated operating subsidiaries, which are included in the assessment for 2015 property taxes.

Interest expense of $197.8 million was $12.2 million higher compared to the same period in 2014. Amounts reported for the year ended December 31, 2015 and 2014 exclude approximately $6.0 million and $1.0 million, respectively, of pre-tax expenses associated with the adjustments to operating earnings noted previously. The increase in interest expense was due primarily to higher borrowing levels to finance capital investments.

The effective income tax rate for the year ended December 31, 2015 was 37.4 percent compared to 38.2 percent for the same period in 2014. Amounts reported for the year ended December 31, 2015 and 2014 exclude income taxes of $52.4 million and $30.4 million, respectively, associated with adjustments to operating earnings noted previously.

**Fourth Quarter Conference Call and Webcast**

Joseph L. Welch, chairman, president and CEO and Rejji P. Hayes, senior vice president and CFO will discuss the fourth quarter results in a conference call at 11 a.m. Eastern on Thursday, February 25, 2016. Individuals wishing to participate in the conference call may dial toll-free 877-644-1296 (domestic) or 914-495-8555 (international); there is no passcode. A listen-only live webcast of the conference call, including accompanying slides and the earnings release, will be available on the company’s investor information page. The conference call replay, available through March 1, 2016, and can be accessed by dialing 855-859-2056 (toll free) or 404-537-3406, passcode 35330470. The webcast will be archived on the ITC website.

**Other Available Information**

More detail about the year ended 2015 results may be found in ITC's Form 10-K filing. Once filed with the Securities and Exchange Commission, an electronic copy of our 10-K can be found at our website, http://investor.itc-holdings.com. Paper copies can also be made available by contacting us through our website.

**About ITC Holdings Corp.**

ITC Holdings Corp. (NYSE: ITC) is the nation's largest independent electric transmission company. Based in Novi, Michigan, ITC invests in the electric transmission grid to improve reliability, expand access to markets, allow new generating resources to interconnect to its transmission systems and lower the overall cost of delivered energy. Through its regulated operating subsidiaries ITCTransmission, Michigan Electric Transmission Company, ITC Midwest and ITC Great Plains, 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 megawatts along approximately 15,600 circuit miles of transmission line. ITC's grid development focus includes growth through regulated infrastructure investment as well as domestic and international expansion through merchant and other commercial development opportunities. For more information, please visit ITC's website at www.itc-holdings.com (ITC-itc-F).

**GAAP v. Non-GAAP Measures**

ITC's reported earnings are prepared in accordance with GAAP and represent earnings as reported to the Securities and Exchange Commission. ITC's management believes that operating earnings, or GAAP earnings adjusted for specific items as described in the release that are generally not indicative of our core operations, provides additional information that is useful to investors in understanding ITC's underlying performance, business and performance trends, and helps facilitate period to period comparisons. However, non-GAAP financial measures are not required to be uniformly applied, are not audited and should not be considered in isolation or as substitutes for results prepared in accordance with GAAP.

**Safe Harbor Statement**

This press release contains certain statements that describe our management's beliefs concerning future business conditions, plans and prospects, growth opportunities and the outlook for our business and the electricity transmission industry based upon information currently available. Such statements are "forward-looking" statements within the meaning of the Private Securities Litigation Reform Act of 1995. Wherever possible, we have identified these forward-looking statements by words such as "will," "may," "anticipates," "believes," "intends," "estimates," "expects," "projects" and similar phrases. These forward-looking statements are based upon assumptions our management believes are reasonable. Such forward looking statements are subject to risks and uncertainties which could cause our actual results, performance and achievements to differ materially from those expressed in, or implied by, these statements, including, among others, the risks and uncertainties disclosed in our annual reports on Form 10-K, quarterly reports on Form 10-Q and other filings made with the Securities and Exchange Commission.

Because our forward-looking statements are based on estimates and assumptions that are subject to significant business, economic and competitive uncertainties, many of which are beyond our control or are subject to change, actual results could be materially different and any or all of our forward-looking statements may turn out to be wrong. Forward-looking statements speak only as of the date made and can be affected by assumptions we might make or by known or unknown risks and uncertainties. Many factors mentioned in our discussion in this release and in our annual and quarterly reports will be important in determining future results. Consequently, we cannot assure you that our expectations or forecasts expressed in such forward-looking statements will be achieved. Except as required by law, we undertake no obligation to publicly update any of our forward-looking or other statements, whether as a result of new information, future events, or otherwise.

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**ITC HOLDINGS CORP. AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF OPERATIONS**

| (in thousands, except per share data) | Three months ended December 31, 2015 | Three months ended December 31, 2014 | Twelve months ended December 31, 2015 | Twelve months ended December 31, 2014 |
|---|---|---|---|---|
| **OPERATING REVENUES** | $ 224,034 | $ 231,097 | $ 1,044,768 | $ 1,023,048 |
| **OPERATING EXPENSES** | | | | |
| Operation and maintenance | 24,814 | 31,888 | 113,123 | 111,623 |
| General and administrative | 37,855 | 27,949 | 144,919 | 115,031 |
| Depreciation and amortization | 37,769 | 33,427 | 144,672 | 128,036 |
| Taxes other than income taxes | 20,725 | 19,060 | 82,354 | 76,534 |
| Other operating income and expense — net | (342) | (255) | (1,017) | (1,005) |
| Total operating expenses | 120,821 | 112,069 | 484,051 | 430,219 |
| **OPERATING INCOME** | 103,213 | 119,028 | 560,717 | 592,829 |
| **OTHER EXPENSES (INCOME)** | | | | |
| Interest expense — net | 53,709 | 48,145 | 203,779 | 186,636 |
| Allowance for equity funds used during construction | (6,641) | (5,960) | (28,075) | (20,825) |
| Loss on extinguishment of debt | — | 131 | — | 29,205 |
| Other income | (1,245) | (462) | (2,071) | (1,103) |
| Other expense | 216 | 792 | 3,207 | 4,511 |
| Total other expenses (income) | 46,039 | 42,646 | 176,840 | 198,424 |
| **INCOME BEFORE INCOME TAXES** | 57,174 | 76,382 | 383,877 | 394,405 |
| **INCOME TAX PROVISION** | 19,809 | 29,644 | 141,471 | 150,322 |
| **NET INCOME** | $ 37,365 | $ 46,738 | $ 242,406 | $ 244,083 |
| Basic earnings per common share | $ 0.25 | $ 0.30 | $ 1.57 | $ 1.56 |
| Reported diluted earnings per common share | $ 0.24 | $ 0.30 | $ 1.56 | $ 1.54 |
| Operating diluted earnings per common share | $ 0.57 | $ 0.48 | $ 2.08 | $ 1.85 |
| Dividends declared per common share | $ 0.188 | $ 0.163 | $ 0.700 | $ 0.610 |

**RECONCILIATION OF REPORTED NET INCOME (GAAP) TO OPERATING EARNINGS (NON-GAAP MEASURE) - UNAUDITED**

| | Three months ended December 31, 2015 | Three months ended December 31, 2014 | Twelve months ended December 31, 2015 | Twelve months ended December 31, 2014 |
|---|---|---|---|---|
| Reported net income (GAAP) | $ 37,365 | $ 46,738 | $ 242,406 | $ 244,083 |
| After-tax regulatory charges | 621 | 2 | 7,253 | 134 |
| After-tax debt extinguishment & consent solicitation fees | — | 157 | — | 18,205 |
| After-tax MISO regional base ROE rate refund liability(1) | 48,630 | 28,903 | 73,171 | 28,903 |
| After-tax review of strategic alternatives expenses | 976 | — | 976 | — |
| After-tax Entergy transaction related expenses | — | 113 | — | 714 |
| Operating earnings (non-GAAP) | $ 87,592 | $ 75,913 | $ 323,806 | $ 292,039 |

**RECONCILIATION OF REPORTED DILUTED EPS (GAAP) TO OPERATING DILUTED EPS (NON-GAAP MEASURE) - UNAUDITED**

| | Three months ended December 31, 2015 | Three months ended December 31, 2014 | Twelve months ended December 31, 2015 | Twelve months ended December 31, 2014 |
|---|---|---|---|---|
| Reported diluted EPS (GAAP) | $ 0.24 | $ 0.30 | $ 1.56 | $ 1.54 |
| After-tax regulatory charges | — | — | 0.04 | — |
| After-tax debt extinguishment & consent solicitation fees | — | — | — | 0.12 |
| After-tax MISO regional base ROE rate refund liability(1) | 0.32 | 0.18 | 0.47 | 0.18 |
| After-tax review of strategic alternatives expenses | 0.01 | — | 0.01 | — |
| After-tax Entergy transaction related expenses | — | — | — | 0.01 |
| Operating diluted EPS (non-GAAP) | $ 0.57 | $ 0.48 | $ 2.08 | $ 1.85 |

(1)Amounts recorded for fourth quarter and year ended December 31, 2015 include after-tax amounts of $36.8 million, or $0.24 per diluted common share, and $28.4 million, or $0.18 per diluted common share, respectively, related to adjustments to prior periods associated with the refund liability.

**ITC HOLDINGS CORP. AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF FINANCIAL POSITION**

| (in thousands, except share data) | | December 31, 2015 | | December 31, 2014 |
|---|---|---|---|---|
| **ASSETS** | | | | |
| **Current assets** | | | | |
| Cash and cash equivalents | $ | 13,859 | $ | 27,741 |
| Accounts receivable | | 104,262 | | 100,998 |
| Inventory | | 25,777 | | 30,892 |
| Regulatory assets | | 14,736 | | 5,393 |
| Prepaid and other current assets | | 10,608 | | 7,281 |
| Total current assets | | 169,242 | | 172,305 |
| **Property, plant and equipment** (net of accumulated depreciation and amortization of $1,487,713 and $1,388,217, respectively) | | 6,109,639 | | 5,496,875 |
| **Other assets** | | | | |
| Goodwill | | 950,163 | | 950,163 |
| Intangible assets (net of accumulated amortization of $28,242 and $24,917, respectively) | | 45,602 | | 48,794 |
| Regulatory assets | | 233,376 | | 223,712 |
| Deferred financing fees (net of accumulated amortization of $17,515 and $15,972, respectively) | | 29,298 | | 30,311 |
| Other | | 44,802 | | 37,418 |
| Total other assets | | 1,303,241 | | 1,290,398 |
| **TOTAL ASSETS** | $ | 7,582,122 | $ | 6,959,578 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | | | |
| **Current liabilities** | | | | |
| Accounts payable | $ | 124,331 | $ | 107,969 |
| Accrued payroll | | 24,123 | | 23,502 |
| Accrued interest | | 52,577 | | 50,538 |
| Accrued taxes | | 44,256 | | 41,614 |
| Regulatory liabilities | | 44,964 | | 39,972 |
| Refundable deposits from generators for transmission network upgrades | | 2,534 | | 10,376 |
| Debt maturing within one year | | 395,334 | | 175,000 |
| Other | | 31,034 | | 14,043 |
| Total current liabilities | | 719,153 | | 463,014 |
| **Accrued pension and postretirement liabilities** | | 61,609 | | 69,562 |
| **Deferred income taxes** | | 735,426 | | 642,051 |
| **Regulatory liabilities** | | 254,788 | | 160,070 |
| **Refundable deposits from generators for transmission network upgrades** | | 18,077 | | 9,384 |
| **Other** | | 23,075 | | 17,354 |
| **Long-term debt** | | 4,060,923 | | 3,928,586 |
| **Commitments and contingent liabilities (Notes 4 and 16)** | | | | |
| **STOCKHOLDERS' EQUITY** | | | | |
| Common stock, without par value, 300,000,000 shares authorized, 152,699,077 and 155,140,967 shares issued and outstanding at December 31, 2015 and 2014, respectively | | 829,211 | | 923,191 |
| Retained earnings | | 875,595 | | 741,550 |
| Accumulated other comprehensive income | | 4,265 | | 4,816 |
| Total stockholders' equity | | 1,709,071 | | 1,669,557 |
| **TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY** | $ | 7,582,122 | $ | 6,959,578 |

**ITC HOLDINGS CORP. AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOW**

| (in thousands) | Twelve months ended December 31, 2015 | 2014 |
|---|---|---|
| **CASH FLOWS FROM OPERATING ACTIVITIES** | | |
| Net income | $ 242,406 | $ 244,083 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization expense | 144,672 | 128,036 |
| Recognition of and refund and collection of revenue accruals and deferrals — including accrued interest | (53,539) | (4,093) |
| Deferred income tax expense | 77,371 | 90,373 |
| Allowance for equity funds used during construction | (28,075) | (20,825) |
| Loss on extinguishment of debt | — | 29,205 |
| Other | 22,031 | 17,697 |
| Changes in assets and liabilities, exclusive of changes shown separately: | | |
| Accounts receivable | (501) | (11,869) |
| Inventory | 5,140 | 1,094 |
| Prepaid and other current assets | (3,214) | 5,089 |
| Accounts payable | (7,263) | (19,061) |
| Accrued payroll | 463 | 525 |
| Accrued interest | 2,039 | (2,511) |
| Accrued taxes | 14,783 | 19,756 |
| Tax benefit on the excess tax deduction of share-based compensation | (11,707) | (7,767) |
| Other current liabilities | 5,587 | (2,314) |
| Estimated potential refund related to return on equity complaints | 120,197 | 47,780 |
| Other non-current assets and liabilities, net | 25,355 | (13,697) |
| Net cash provided by operating activities | 555,745 | 501,501 |
| **CASH FLOWS FROM INVESTING ACTIVITIES** | | |
| Expenditures for property, plant and equipment | (684,140) | (733,145) |
| Proceeds from sale of marketable securities | 673 | 495 |
| Purchases of marketable securities | (10,422) | (6,091) |
| Other | (5,456) | 4,040 |
| Net cash used in investing activities | (699,345) | (734,701) |
| **CASH FLOWS FROM FINANCING ACTIVITIES** | | |
| Issuance of long-term debt | 225,000 | 798,664 |
| Borrowings under revolving credit agreements | 2,832,100 | 1,660,000 |
| Borrowings under term loan credit agreements | 200,000 | 110,000 |
| Net issuance of commercial paper, net of discount | 94,630 | — |
| Retirement of long-term debt — including extinguishment of debt costs | (175,000) | (298,625) |
| Repayments of revolving credit agreements | (2,825,000) | (1,618,400) |
| Repayments of term loan credit agreements | — | (189,000) |
| Issuance of common stock | 13,635 | 20,713 |
| Dividends on common and restricted stock | (108,275) | (95,595) |
| Refundable deposits from generators for transmission network upgrades | 12,956 | 5,833 |
| Repayment of refundable deposits from generators for transmission network upgrades | (12,025) | (28,683) |
| Repurchase and retirement of common stock | (137,081) | (134,284) |
| Tax benefit on the excess tax deduction of share-based compensation | 11,707 | 7,767 |
| Advance for forward contract of accelerated share repurchase program | — | (20,000) |
| Return of unused advance for forward contract of accelerated share repurchase program | — | 20,000 |
| Other | (2,929) | (11,724) |
| Net cash provided by financing activities | 129,718 | 226,666 |
| **NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS** | (13,882) | (6,534) |
| **CASH AND CASH EQUIVALENTS — Beginning of period** | 27,741 | 34,275 |
| **CASH AND CASH EQUIVALENTS — End of period** | $ 13,859 | $ 27,741 |