Emera

# Management’s Discussion & Analysis

As at February 12, 2016

Management’s Discussion & Analysis (“MD&A”) provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments (“Emera”) during the fourth quarter of 2015 relative to the same quarter in 2014; and the full year of 2015 relative to 2014 and 2013; and its financial position as at December 31, 2015 relative to December 31, 2014. To enhance shareholders’ understanding, certain multi-year historical financial and statistical information is presented. Throughout this discussion, “Emera Incorporated”, “Emera” and “Company” refer to Emera Incorporated and all of its consolidated subsidiaries and investments.

This discussion and analysis should be read in conjunction with the Emera Incorporated annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2015. Emera follows United States Generally Accepted Accounting Principles (“USGAAP” or “GAAP”).

The accounting policies used by Emera’s rate-regulated entities may differ from those used by Emera’s non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. Emera’s rate-regulated subsidiaries include:

| Emera Rate-Regulated Subsidiary or Investment | Accounting Policies Approved/Examined By |
|---|---|
| **Subsidiary** | |
| Nova Scotia Power Inc. (“NSPI”) | Nova Scotia Utility and Review Board (“UARB”) |
| Emera Maine | Maine Public Utilities Commission (“MPUC”) and the Federal Energy Regulatory Commission (“FERC”) |
| Barbados Light & Power Company Limited (“BLPC”) | Fair Trading Commission, Barbados |
| Grand Bahama Power Company Limited (“GBPC”) | The Grand Bahama Port Authority (“GBPA”) |
| Dominica Electricity Services Ltd. (“Domlec”) | Independent Regulatory Commission (“IRC”), Dominica |
| Emera Brunswick Pipeline Company Limited (“Brunswick Pipeline”) | National Energy Board (“NEB”) |
| **Investment** | |
| NSP Maritime Link Inc. (“NSPML”) | UARB |
| Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline LLC (“M&NP”) | NEB and FERC |
| Labrador Island Link Limited Partnership (“LIL”) | Newfoundland and Labrador Board of Commissioners of Public Utilities |
| St. Lucia Electricity Services Limited (“Lucelec”) | Government of St. Lucia |

All amounts are in Canadian dollars (“CAD”), except for Emera Maine and Emera Caribbean sections of the MD&A, which are reported in US dollars (“USD”), unless otherwise stated.

Additional information related to Emera, including the Company’s Annual Information Form, can be found on SEDAR at www.sedar.com.

# Forward-Looking Information

This MD&A contains “forward-looking information” and statements which reflect the current view with respect to the Company’s expectations regarding future growth, results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes within the meaning of applicable Canadian securities laws. All such information and statements are made pursuant to safe harbor provisions contained in applicable securities legislation. The words “anticipates”, “believes”, “could”, “estimates”, “expects”, “intends”, “may”, “plans”, “projects”, “schedule”, “should”, “budget”, “forecast”, “might”, “will”, “would”, “targets” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management’s current beliefs and is based on information currently available to Emera’s management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the time at which, such events, performance or results will be achieved.

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations are discussed in the Outlook section of the MD&A and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; capital market and liquidity risk; the completion of the TECO Energy, Inc. (“TECO Energy”) acquisition; uncertainty regarding the length of time required to complete the TECO Energy acquisition; future dividend growth; timing and costs associated with certain capital projects; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology could reduce demand for electricity; weather; commodity price risk; construction and development risk; unanticipated maintenance and other expenditures; derivative financial instruments and hedging availability and inability to complete the Debenture Offering and the financing; failure by the Company to repay the acquisition credit facilities; potential unavailability of the acquisition credit facilities; alternate sources of funding that would be used to replace the acquisition credit facilities may not be available when needed; impact of acquisition related expenses; interest rate risk; credit risk; commercial relationship risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

# Structure of MD&A

This MD&A begins with an Introduction and Strategic Overview; followed by the Consolidated Financial Review and Outstanding Common Stock data; then presents information specific to Emera's consolidated subsidiaries and investments:

- NSPI;
- Emera Maine;
- Emera Caribbean includes BLPC and Domlec and their parent company, Emera (Caribbean) Incorporated ("ECI"), GBPC, Emera Utility Services (Bahamas) Limited ("EUS Bahamas") and Lucelec;
- Pipelines includes Brunswick Pipeline and M&NP;
- Emera Energy includes Emera Energy Services ("EES"); Emera Energy Generation ("EEG") which includes Bridgeport Energy, Tiverton Power and Rumford Power ("New England Gas Generating Facilities"), Brooklyn Power Corporation ("Brooklyn Energy" or "Brooklyn") and Bayside Power Limited Partnership ("Bayside Power" or "Bayside"); Bear Swamp Power Company LLC ("Bear Swamp"); and Northeast Wind Partners II, LLC ("NWP") until its sale on January 29, 2015;
- Corporate and Other includes:
    - Interest revenue on intercompany financings and costs associated with corporate activities that are not directly allocated to the operations of Emera's consolidated subsidiaries and investments;
    - Acquisition costs related to the pending acquisition of TECO Energy;
    - Emera Utility Services Inc. ("Emera Utility Services");
    - Emera Newfoundland & Labrador Holdings Inc. ("ENL") and its investments:
        - NSPML;
        - LIL;
    - Emera Reinsurance Limited;
    - Emera's investment in Algonquin Power & Utilities Corp. ("APUC");
    - Emera's investment in OpenHydro Group Ltd. ("Open Hydro"); and
    - Other investments

The Liquidity and Capital Resources, including Consolidated Cash Flow Highlights, Pension Funding, Off-Balance Sheet Arrangements, Outlook, Transactions with Related Parties, Dividends and Payout Ratios, Enterprise Risk and Risk Management, including Financial Instruments, Disclosure and Internal Controls, Critical Accounting Estimates, Changes in Accounting Policies and Practices and Summary of Quarterly Results sections of the MD&A are presented on a consolidated basis.

# INTRODUCTION AND STRATEGIC OVERVIEW

Emera Incorporated is a geographically diverse energy and services company that invests in electricity generation, transmission and distribution, as well as gas transmission and utility services. Emera provides regional energy solutions by connecting its assets, markets and partners in Canada, the United States, and the Caribbean.

Emera seeks to deliver long-term growth to investors and, accordingly, annual dividend growth, earnings per common share growth and total shareholder return are the primary measures of performance. Emera is targeting eight-per-cent annual dividend growth through 2019. Below are Emera's one, three and five-year performance for these metrics:

| For the | Year ended December 31, 2015 | | |
|---|---|---|---|
| | 1 year | 3 year | 5 year |
| Dividend per share compound annual growth rate | 12.7% | 6.9% | 7.4% |
| Adjusted earnings per share compound annual growth rate | 1.3% | 6.9% | 5.9% |
| Emera annualized total shareholder return (1) | 16.4% | 12.1% | 11.1% |
| S&P/TSX Capped Utilities Index annualized total shareholder return (2) | (3.5)% | 2.3% | 3.5% |

(1) Total shareholder return combines share price appreciation and dividends per common share paid during the fiscal year to show the total return to the shareholder expressed as an annualized percentage assuming dividends are reinvested each time they are paid.
(2) The S&P/TSX Capped Sector Indices provide liquid and tradable benchmarks for related derivative products of Canadian economic sectors. Constituents are selected from a stock pool of S&P/TSX Composite Index Stocks, and the relative weight of any single index constituent is capped at 25 per cent. The indices are based upon the Global Industry Classification Standards (GICS®). The S&P/TSX Capped Utilities imposes capped weights on the index constituents included in the S&P/TSX Composite that are classified in the GICS® utilities sector.

Energy markets worldwide, in particular across North America, are undergoing foundational changes that have created significant investment opportunities for companies with Emera's experience and capabilities. Key trends contributing to these investment opportunities include: aging infrastructure, environmental concerns (including demand for new, less carbon-intensive and renewable generation), lower-cost natural gas, growing demand for new electric heating solutions, and the requirement for large-scale transmission projects to deliver new energy sources to customers. Within this context, Emera is focused on growing shareholder value by identifying reliable and affordable energy solutions, typically involving the replacement of higher-carbon electricity generation with generation from cleaner sources, and the related transmission and distribution infrastructure to deliver that energy to market.

Emera has strong partnerships and relationships throughout the regions in which it operates and has established a diverse investment and operations profile that links its assets and capabilities in those regions. Core to Emera's strategy is the ability to leverage these particular linkages and adjacencies to create solutions for customers and investment opportunities for the Company.

Emera's strategy is based on its collaborative approach to strategic partnerships, its ability to find creative solutions to work within and across multiple jurisdictions, and its experience dealing with complex projects and investment structures. The Company will continue to make investments in its regulated utilities to benefit customers and focus on providing rate stability to its customers. From time to time, Emera will make acquisitions, both regulated and unregulated, where the business or asset acquired aligns with Emera's strategic initiatives and delivers shareholder value.

To ensure stability in net income and cash flows, Emera employs operating and governance models that focus on operational excellence, constructive regulatory approaches, proactive stakeholder engagement and a customer focus through service reliability and rate stability.

Emera targets achieving 75 to 85 per cent of its adjusted income (a non-GAAP measure described in the section below) from rate-regulated subsidiaries, which generally contribute strong, predictable income and cash flows that fund dividends, reinvestment and is reflective of the Company's risk tolerance. Emera has an annual dividend growth target of eight per cent through 2019.

In 2015, approximately 65 per cent of Emera's adjusted net income was earned by its rate-regulated subsidiaries, which is lower than previous years and the strategic target. With the pending close of the TECO Energy acquisition, the Company will achieve its adjusted net income targeted mix. Specifically, this was as the result of a substantial increase in Emera Energy's earnings primarily due to strong performance by the New England Gas Generating Facilities, and a strengthening US dollar. The current percentage from non-regulated businesses is not the result of a change in Emera's risk tolerance, nor is it from additional capital allocations to non-regulated businesses. Rather, it is the result of strong operating and financial performance of existing non-regulated investments and businesses.

Emera has grown its asset base to enable growth and deliver on its strategic objectives. Over the last 10 years, Emera's ability to raise the capital necessary to fund investments has been a strong enabler of the Company's growth. This was demonstrated in Emera's recent issue of convertible debentures represented by instalment receipts in relation to the pending TECO Energy acquisition. In addition to access to debt and equity capital markets, cash flow from operations will continue to play a role in financing the Company's future growth. Maintaining strong, investment grade credit ratings is an important component of Emera's financing strategy.

The energy industry is seasonal in nature. Seasonal patterns and other weather events, including the number and severity of storms, can affect demand for energy and cost of service. Similarly, mark-to-market adjustments arising from commodity purchases or trading activities that do not qualify for hedge accounting or regulatory accounting can have a material impact on the financial results for a specific period. Results in any one quarter are not necessarily indicative of results in any other quarter, or for the year as a whole.

# Non-GAAP Financial Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period, as detailed below:

| Non-GAAP measure | GAAP measure |
|---|---|
| Adjusted net income attributable to common shareholders or adjusted net income | Net income attributable to common shareholders |
| Adjusted earnings per common share – basic | Earnings per common share – basic |
| Adjusted contribution to consolidated net income | Contribution to consolidated net income |
| Adjusted income before provision for income taxes | Income before provision for income taxes |
| Adjusted contribution to consolidated earnings per common share – basic | Contribution to consolidated earnings per common share – basic |
| EBITDA | Net income |
| Adjusted EBITDA | Net income |
| Electric margin | Income from operations |

**Adjusted Net Income**

Emera calculates comparable measures by excluding the effect of:

- the mark-to-market adjustments related to Emera's held-for-trading ("HFT") derivative instruments;
- the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp and NWP, until NWP's sale on January 29, 2015;
- the amortization of transportation capacity recognized as a result of certain trading and marketing transactions;
- the mark-to-market adjustments related to an interest rate swap in Brunswick Pipeline; and
- the mark-to-market adjustments included in Emera's other income related to the effect of USD-denominated currency and forward contracts. These contracts were put in place to economically hedge the anticipated proceeds from the Debenture Offering for the pending TECO Energy acquisition.

Management believes excluding from income the effect of these mark-to-market valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows.

Mark-to-market adjustments are further discussed in the Consolidated Financial Highlights section, Emera Energy – Review of 2015, Pipelines – Review of 2015 and Corporate and Other – Review of 2015.

The following is a reconciliation of reported net income attributable to common shareholders to adjusted net income attributable to common shareholders, and reported earnings per common share – basic to adjusted earnings per common share – basic:

| For the<br>millions of Canadian dollars (except per share amounts) | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Net income attributable to common shareholders | **$ 192.1** | $ 151.2 | **$ 397.2** | $ 406.7 | $ 217.5 |
| After-tax mark-to-market gain (loss) | **$ 105.0** | $ 72.7 | **$ 67.2** | $ 87.5 | $ (41.9) |
| Adjusted net income attributable to common shareholders | **$ 87.1** | $ 78.5 | **$ 330.0** | $ 319.2 | $ 259.4 |
| Earnings per common share – basic | **$ 1.31** | $ 1.05 | **$ 2.72** | $ 2.84 | $ 1.64 |
| Adjusted earnings per common share – basic | **$ 0.59** | $ **0.54** | **$ 2.26** | $ 2.23 | $ 1.96 |

**EBITDA and Adjusted EBITDA**

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") is a non-GAAP financial measure used by Emera. EBITDA is used by numerous investors and lenders to better understand cash flows and credit quality.

Adjusted EBITDA is a non-GAAP financial measure used by Emera. Similar to Adjusted Net Income calculations, this measure represents EBITDA absent the income effect of Emera's mark-to-market adjustments, as previously discussed.

The Company's EBITDA and Adjusted EBITDA may not be comparable to the EBITDA measures of other companies, but in management's view appropriately reflects Emera's specific financial condition. These measures are not intended to replace "Net income attributable to common shareholders" which, as determined in accordance with GAAP, is an indicator of operating performance. EBITDA and Adjusted EBITDA are discussed further in the Consolidated Financial Review, NSPI, Emera Maine, Emera Caribbean, Pipelines, Emera Energy, and Corporate and Other sections.

**EBITDA and Adjusted EBITDA Reconciliation**

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Net income | **$ 198.6** | $ 155.3 | **$ 452.4** | $ 452.8 | $ 255.3 |
| Interest expense, net | **70.9** | 44.7 | **212.6** | 179.8 | 172.2 |
| Income tax expense (recovery) | **20.7** | 53.7 | **92.4** | 113.6 | 43.3 |
| Depreciation and amortization | **87.9** | 82.0 | **339.9** | 329.0 | 297.8 |
| EBITDA | **378.1** | 335.7 | **1,097.3** | 1,075.2 | 768.6 |
| Mark-to-market gain (loss), excluding income tax and interest | **119.3** | 107.7 | **66.1** | 128.7 | (60.9) |
| Adjusted EBITDA | **$ 258.8** | $ 228.0 | **$ 1,031.2** | $ 946.5 | $ 829.5 |

**Electric Margin**

"Electric margin" is a non-GAAP financial measure used to show the amounts that NSPI, BLPC, GBPC and Domlec retain to recover non-fuel costs. Prudently incurred fuel costs are recovered from customers, except in Domlec, where substantially all fuel costs are passed to customers through the fuel pass-through mechanism. Management believes measuring electric margin shows the portion of the utilities' revenues that directly contribute to Emera's income as distinguished from the portion of revenues that are managed through fuel adjustment mechanisms, which have a minimal impact on income.

Emera Energy also reports "Electric margin" because the sales price of electricity and the cost of natural gas used to generate it are highly correlated. However, their absolute values can vary materially over time. Emera Energy believes that "Electric margin", as the net result, provides a meaningful measure of the business' performance in addition to the absolute values of sales and fuel expenses, which are also reported.

Electric margin, as calculated by Emera, may not be comparable to the electric margin measures of other companies, but in management's view appropriately reflects Emera's specific condition. This measure is not intended to replace "Income from operations" which, as determined in accordance with GAAP, is an indicator of operating performance. Electric margin is discussed further in the NSPI – Electric Margin, the Emera Caribbean – Electric Margin and the Emera Energy – Adjusted EBITDA sections.

# Significant Items Affecting Earnings

**2015**

**After-Tax Mark-to-Market Gains**

After-tax mark-to-market gains increased $32.3 million to $105.0 million in Q4 2015 compared to $72.7 million in Q4 2014; and decreased $20.3 million to $67.2 million for the year ended December 31, 2015 compared to $87.5 million in 2014. The increased mark-to-market gains in the quarter are primarily due to the effect of USD-denominated currency and forward contracts related to the pending TECO Energy acquisition. The increase is partially offset by changes in gas and power contract positions and amortization of transportation assets in Emera Energy. In addition, the reversal of 2013 mark-to-market losses in 2014 in Emera Energy is primarily responsible for the year-over-year decrease in after-tax mark-to-market gains.

**Acquisition Related Costs**

Emera incurred after-tax costs of $30.3 million ($0.21 per common share) in Q4 2015 related to its pending acquisition of TECO Energy, including legal, advisory, and financing costs. For the year ended December 31, 2015, TECO Energy acquisition related costs were $52.8 million after-tax ($0.36 per common share). There were no such TECO Energy acquisition related costs for 2014.

As discussed and included above in "After-Tax Mark-to-Market Gains", the foreign currency earnings effect related to the Debenture Offering USD cash balance and the forward contracts were recorded as a mark-to-market pre-tax gain of $118.9 million in "Other income (expenses), net" in Q4 2015.

Further information on the pending acquisition of TECO Energy is in the Developments section of the MD&A.

**Gain on Dilution of APUC Equity Investment**

In December 2015, APUC closed a 14.355 million common share offering. As a result, Emera recorded a dilution gain of $11.1 million (after-tax earnings of $9.4 million or $0.06 per common share) in "Income from Equity Investments". The gain was a result of APUC's share issuance price being higher than Emera's pre-issuance average book value.

**Barbados Light & Power Company Limited ("BLPC") Restructuring Costs**

BLPC recorded severance costs of $7.9 million ($6.4 million USD) relating to corporate restructuring, which was recorded in Operating, maintenance and general ("OM&G") in Q2 2015. BLPC sees no requirement to seek regulatory deferral of these costs. The after-tax effect on Emera's Consolidated Net Income in Q2 2015, at Emera's then 80.7 per cent ownership of ECI, was $5.4 million ($0.04 per common share).

**Sale of Northeast Wind Partnership II, LLC Equity Investment**

On January 29, 2015, Emera completed the sale of its 49 per cent interest in NWP for $282.3 million ($223.3 million USD). This sale resulted in a pre-tax gain of $18.6 million or $0.13 per common share (after-tax gain of $11.5 million or $0.08 per common share), which was recorded in "Other income (expenses), net" in Q1 2015.

**2014**

**After-Tax Mark-to-Market Gains**

After-tax mark-to-market gains (losses) increased $114.7 million to $72.7 million in Q4 2014 compared to $(42.0) million in Q4 2013; and increased $129.4 million to $87.5 million for the year ended December 31, 2014 compared to $(41.9) million in 2013. The increased mark-to-market gains are a result of the reversal of 2013 mark-to-market losses and favourable changes in gas and power contract positions in 2014 at Emera Energy.

**Gains on Dilution of APUC Equity Investment**

In Q3 2014 and Q4 2014 respectively, APUC closed 16.86 million and 10.05 million common share offerings. In addition, in Q3 2014, an over-allotment option of 2.52 million common shares was exercised. As a result of these two transactions, in Q3 2014, Emera recorded a gain of $10.8 million (after-tax earnings of $9.1 million or $0.06 per common share) and in Q4 2014, a gain of $7.5 million (after-tax earnings of $6.4 million or $0.04 per common share) in "Income from Equity Investments".

# CONSOLIDATED FINANCIAL REVIEW

## Consolidated Financial Highlights

| For the<br>millions of Canadian dollars (except per share amounts) | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Operating revenues | **$ 731.6** | $ 782.7 | **$ 2,789.3** | $ 2,938.6 | $ 2,230.2 |
| Income from operations | **149.0** | 235.4 | **507.7** | 667.3 | 407.1 |
| Net income attributable to common shareholders | **192.1** | 151.2 | **397.2** | 406.7 | 217.5 |
| After-tax mark-to-market gain (loss) | **105.0** | 72.7 | **67.2** | 87.5 | (41.9) |
| Adjusted net income attributable to common shareholders | **87.1** | 78.5 | **330.0** | 319.2 | 259.4 |
| Earnings per common share – basic | **$ 1.31** | $ 1.05 | **$ 2.72** | $ 2.84 | $ 1.64 |
| Earnings per common share – diluted | **$ 1.30** | $ 1.02 | **$ 2.71** | $ 2.82 | $ 1.64 |
| Adjusted earnings per common share – basic | **$ 0.59** | $ 0.54 | **$ 2.26** | $ 2.23 | $ 1.96 |
| Dividends per common share declared | **$ -** | $ - | **$ 1.6625** | $ 1.4750 | $ 1.4125 |
| | | | | | |
| Adjusted EBITDA | **$ 258.8** | $ 228.0 | **$ 1,031.2** | $ 946.5 | $ 829.5 |

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| **Operating Unit Contributions to Adjusted Net Income** | **2015** | 2014 | **2015** | 2014 | 2013 |
| NSPI | **$ 40.1** | $ 30.1 | **$ 129.9** | $ 124.9 | $ 126.0 |
| Emera Maine | **5.2** | 11.7 | **45.1** | 42.4 | 38.4 |
| Emera Caribbean | **13.3** | 6.1 | **40.5** | 28.7 | 33.4 |
| Pipelines | **10.1** | 8.5 | **39.6** | 32.7 | 30.3 |
| Emera Energy | **35.4** | 21.3 | **130.1** | 98.2 | 45.1 |
| Corporate and Other | **(17.0)** | 0.8 | **(55.2)** | (7.7) | (13.8) |
| Adjusted net income attributable to common shareholders | **$ 87.1** | $ 78.5 | **$ 330.0** | $ 319.2 | $ 259.4 |
| After-tax mark-to-market gain (loss) | **105.0** | 72.7 | **67.2** | 87.5 | (41.9) |
| Net income attributable to common shareholders | **$ 192.1** | $ 151.2 | **$ 397.2** | $ 406.7 | $ 217.5 |

| For the<br>millions of Canadian dollars | Year ended<br>December 31 | | |
|---|---|---|---|
| | **2015** | 2014 | 2013 |
| Operating cash flow before changes in working capital | **$ 775.8** | $ 716.3 | $ 574.3 |
| Change in working capital | **(101.6)** | 46.2 | (10.1) |
| Operating cash flow | **$ 674.2** | $ 762.5 | $ 564.2 |
| Investing cash flow | **$ (123.7)** | $ (710.9) | $ (921.6) |
| Financing cash flow | **$ 221.1** | $ 58.2 | $ 362.1 |

| As at<br>millions of Canadian dollars | December 31<br>**2015** | 2014 | 2013 |
|---|---|---|---|
| Working capital [1] | **$ 599.2** | $ 358.3 | $ 372.7 |
| Total assets [1] | **$ 12,012.3** | $ 9,853.4 | $ 8,876.8 |
| Total long-term liabilities [1] | **$ 5,596.9** | $ 5,025.1 | $ 4,449.7 |

[1] These financial statements contain certain reclassifications of prior period amounts to be consistent with the current period presentation, with no effect on net income.

# REVIEW OF 2015
# Emera Consolidated Statements of Income

| For the<br>millions of Canadian dollars (except per share amounts) | | Three months ended December 31 | | | Year ended December 31 |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Operating revenues – regulated | **$ 533.8** | $ 526.7 | **$ 2,192.9** | $ 2,113.1 | $ 2,040.8 |
| Operating revenues – non-regulated | **197.8** | 256.0 | **596.4** | 825.5 | 189.4 |
| **Total operating revenues** | **731.6** | 782.7 | **2,789.3** | 2,938.6 | 2,230.2 |
| Regulated fuel for generation and purchased power | **199.9** | 212.9 | **814.5** | 844.3 | 868.4 |
| Regulated fuel adjustment mechanism and fixed cost deferrals | **10.3** | 5.7 | **41.6** | 46.6 | (40.8) |
| Non-regulated fuel for generation and purchased power | **90.7** | 78.2 | **335.7** | 401.1 | 89.8 |
| Non-regulated direct costs | **4.4** | 9.7 | **19.5** | 31.3 | 52.4 |
| Operating, maintenance and general | **173.6** | 144.0 | **666.8** | 560.8 | 505.0 |
| Provincial, state and municipal taxes | **15.8** | 14.8 | **63.6** | 58.2 | 50.5 |
| Depreciation and amortization | **87.9** | 82.0 | **339.9** | 329.0 | 297.8 |
| Total operating expenses | **582.6** | 547.3 | **2,281.6** | 2,271.3 | 1,823.1 |
| **Income from operations** | **149.0** | 235.4 | **507.7** | 667.3 | 407.1 |
| Income from equity investments | **26.4** | 15.4 | **108.6** | 66.6 | 38.1 |
| Other income (expenses), net | **114.8** | 2.9 | **141.1** | 12.3 | 25.6 |
| Interest expense, net | **70.9** | 44.7 | **212.6** | 179.8 | 172.2 |
| **Income before provision for income taxes** | **219.3** | 209.0 | **544.8** | 566.4 | 298.6 |
| Income tax expense (recovery) | **20.7** | 53.7 | **92.4** | 113.6 | 43.3 |
| **Net income** | **198.6** | 155.3 | **452.4** | 452.8 | 255.3 |
| Non-controlling interest in subsidiaries | **6.5** | 4.1 | **24.9** | 19.9 | 18.5 |
| **Net income of Emera Incorporated** | **192.1** | 151.2 | **427.5** | 432.9 | 236.8 |
| Preferred stock dividends | **-** | - | **30.3** | 26.2 | 19.3 |
| **Net income attributable to common shareholders** | **192.1** | 151.2 | **397.2** | 406.7 | 217.5 |
| After-tax mark-to-market gain (loss) | **105.0** | 72.7 | **67.2** | 87.5 | (41.9) |
| Adjusted net income attributable to common shareholders | **$ 87.1** | $ 78.5 | **$ 330.0** | $ 319.2 | $ 259.4 |
| Earnings per common share – basic | **$ 1.31** | $ 1.05 | **$ 2.72** | $ 2.84 | $ 1.64 |
| Earnings per common share – diluted | **$ 1.30** | $ 1.02 | **$ 2.71** | $ 2.82 | $ 1.64 |
| Adjusted earnings per common share – basic | **$ 0.59** | $ 0.54 | **$ 2.26** | $ 2.23 | $ 1.96 |

Emera Incorporated's consolidated net income attributable to common shareholders increased $40.9 million to $192.1 million in Q4 2015 compared to $151.2 million for the same period in 2014. For the year ended December 31, 2015, Emera's consolidated net income attributable to common shareholders decreased $9.5 million to $397.2 million compared to $406.7 million in 2014.

# Q4 Consolidated Income Statement Highlights

## Operational Results

Income from operations decreased $86.4 million to $149.0 million in Q4 2015 compared to $235.4 million in the same quarter in 2014 primarily due to negative mark-to-market changes of $101.2 million and $21.0 million in costs related to the pending acquisition of TECO Energy. These decreases were partially offset by Emera Energy's increased trading and marketing margin, and increased margin at the New England Gas Generating Facilities.

Details of operating revenues and operating expenses line item variances are described below:

Total operating revenues decreased 6.5 per cent to $731.6 million in Q4 2015 compared to $782.7 million in Q4 2014 primarily due to:

- $113.7 million decrease from changes in mark-to-market impacts;
- $46.0 million increase at the New England Gas Generating Facilities primarily due to major outage work at Bridgeport Energy in 2014 and the effect of a strengthening USD;
- $22.2 million increase in Emera Energy Services reflecting growth in the volume of business and increased investment in transportation capacity;
- $9.5 million decrease at BLPC primarily due to lower fuel revenue reflecting lower fuel prices;
- $6.9 million increase at Emera Maine primarily due to the effect of a strengthening USD, partially offset by decreased sales volumes;
- $5.8 million increase at NSPI as a result of recovery of prior years' fuel costs from a 2014 UARB settlement agreement, partially offset by decreased sales volumes due to weather.

Total operating expenses increased 6.4 per cent to $582.6 million in Q4 2015 compared to $547.3 million in Q4 2014, primarily due to the effect of a strengthening USD, acquisition costs related to the pending TECO Energy acquisition, and increased fuel costs at the New England Gas Generating Facilities reflecting major outage work at Bridgeport Energy in 2014, partially offset by lower fuel prices at BLPC and changes in mark-to-market impacts.

**Income from equity investments**

Income from equity investments increased 71.4 per cent in Q4 2015 to $26.4 million compared to $15.4 million in the same period in 2014, primarily due to higher APUC earnings in 2015 and a higher pre-tax gain on dilution of Emera's APUC investment in 2015.

**Other income (expenses), net**

Other income increased $111.9 million to $114.8 million in Q4 2015 compared to $2.9 million in the same period in 2014. This was primarily due to mark-to-market gains on USD-denominated currency and forward contracts put in place to economically hedge the anticipated proceeds from the Debenture Offering for the pending TECO Energy acquisition.

**Income tax expense (recovery)**

Income tax expense decreased $33.0 million to $20.7 million in Q4 2015 compared to $53.7 million for the same period in 2014 primarily due to decreased income before provision for income taxes including mark-to-market adjustments related to Emera Energy, changes in the proportion of Emera Energy income earned in higher tax rate foreign jurisdictions, and a legislated change by the Province of Nova Scotia to the deferred tax treatment of two wind farms at NSPI. These decreases were partially offset by the taxable portion of mark-to-market gains relating to the effect of USD-denominated currency and forward contracts put in place to economically hedge the anticipated proceeds from the Debenture Offering for the pending TECO Energy acquisition.

# 2015 Consolidated Income Statement and Operating Cash Flow Highlights

## Operational Results

Income from operations decreased $159.6 million to $507.7 million for the year ended December 31, 2015 compared to $667.3 million in 2014 primarily due to mark-to-market changes of $189.2 million. Increased margin at the New England Gas Generating Facilities, the effect of the strengthening USD, and increased operating income at NSPI, partially offset by $51.5 million in expenses relating to the pending acquisition of TECO Energy and Emera Energy's decreased trading and marketing margin.

Total operating revenues decreased 5.1 per cent to $2,789.3 million for the year ended December 31, 2015 compared to $2,938.6 million in the same period in 2014 primarily due to:

- $203.7 million decrease from changes in mark-to-market impacts
- $47.3 million decrease at BLPC primarily due to lower fuel revenue reflecting lower fuel prices
- $32.6 million decrease in Emera Energy Services reflecting a return to more normal market circumstances following particularly strong market conditions in the northern United States and Ontario in Q1 2014
- $69.1 million increase at NSPI as a result of recovery of prior years' fuel costs from the 2014 UARB settlement agreement and higher sales volumes, primarily due to weather
- $46.3 million increase at the New England Gas Generating Facilities primarily due to higher realized margins, increased generation largely because Bridgeport Energy had a major planned outage in Q4 2014, and the effect of a strengthening USD
- $41.6 million increase at Emera Maine primarily due to the effect of a strengthening USD, partially offset by decreased sales volumes.

Total operating expenses increased 0.5 per cent to $2,281.6 million for the year ended December 31, 2015 compared to $2,271.3 million in 2014. This was primarily due to the effect of a strengthening USD, acquisition costs related to the pending TECO Energy acquisition and increased regulated fuel for generation and purchased power at NSPI, partially offset by decreased fuel costs at the New England Gas Generating Facilities and BLPC reflecting lower fuel prices and changes in mark-to-market impacts.

**Income from equity investments**

Income from equity investments increased $42.0 million to $108.6 million for the year ended December 31, 2015 compared to $66.6 million in the same period of 2014. This was primarily due to favourable mark-to-market changes of $7.7 million, NWP losses in 2014, higher APUC equity earnings, increased allowance for funds used during construction ("AFUDC") earnings by NSPML, and increased earnings resulting from the increased investment in LIL, partially offset by lower APUC dilution gains in 2015 compared to 2014.

**Other income (expenses), net**

Other income increased $128.8 million to $141.1 million for the year ended December 31, 2015 compared to $12.3 million in the same period in 2014. This was primarily due to a mark-to-market gains relating to the foreign exchange effect of USD-denominated currency and forward contracts put in place to economically hedge the anticipated proceeds from the Debenture Offering for the pending TECO Energy acquisition and the gain on the sale of NWP.

**Income tax expense (recovery)**

Income tax expense decreased $21.2 million to $92.4 million for the year ended December 31, 2015 compared to $113.6 million in 2014. This was primarily due to decreased income before provision for income taxes, including mark-to-market adjustments related to Emera Energy, partially offset by the taxable portion of mark-to-market gains relating to the effect of USD-denominated currency and forward contracts put in place to economically hedge the anticipated proceeds from the Debenture Offering financing the pending TECO Energy acquisition.

**Operating Activities**

Net cash provided by operating activities decreased $88.3 million to $674.2 million for the twelve months ended December 31, 2015 compared to $762.5 million for the same period in 2014. Cash from operations before changes in working capital increased by $62.0 million primarily due to higher margins at the New England Gas Generating Facilities, the effect of a strengthening USD and increased fuel electric revenues at NSPI, partially offset by lower trading and marketing margin at Emera Energy Services, payment of acquisition costs related to the pending TECO Energy acquisition and the deferral of demand side management ("DSM") program costs at NSPI.

Changes in working capital decreased operating cash flows by $150.3 million primarily due to increased receivables reflecting higher posted margin at Emera Energy and increased revenues at NSPI and increased dividends payable, partially offset by favourable changes in fuel inventory at NSPI reflecting increased consumption.

**Effect of Foreign Currency Translation**

Emera's foreign currency-denominated results are affected by exchange rate fluctuations. Revenue, operating expense, net income, and adjusted net income are translated at the weighted average rate of exchange. The amounts in the table below are calculated by multiplying the current period foreign denominated results by the change in the weighted average foreign exchange from the prior period. The table below shows the estimated effect of foreign currency translation on key income statement items:

| millions of Canadian dollars (except per share amounts) | Q4 2015 vs Q4 2014 | Q4 2014 vs Q4 2013 |
|---|---|---|
| Impact on income from continuing operations | | |
| Total operating revenues | $ 49.1 | $ 30.7 |
| Total operating expenses | (42.3) | (15.6) |
| Net income | 4.0 | 10.4 |
| Adjusted net income | 7.0 | 2.4 |
| Impact on earnings per share | | |
| Basic | $ 0.03 | $ 0.07 |
| Adjusted | $ 0.05 | $ 0.02 |

| millions of Canadian dollars (except per share amounts) | 2015 vs 2014 | 2014 vs 2013 |
|---|---|---|
| Impact on income from continuing operations | | |
| Total operating revenues | $ 163.6 | $ 98.6 |
| Total operating expenses | (139.4) | (67.0) |
| Net income | 19.2 | 22.0 |
| Adjusted net income | 26.0 | 12.1 |
| Impact on earnings per share | | |
| Basic | $ 0.13 | $ 0.15 |
| Adjusted | $ 0.18 | $ 0.08 |

Emera's weighted average foreign exchange rates are shown in the following table:

| | | | Twelve months ended December 31 |
|---|---|---|---|
| Average equivalent of $1.00 USD | 2015 | 2014 | 2013 |
| CAD | $ 1.26 | $ 1.12 | $ 1.03 |

# Consolidated Balance Sheets Highlights

Significant changes in the consolidated balance sheets between December 31, 2015 and December 31, 2014 include:

| millions of Canadian dollars | Increase (Decrease) | Explanation |
|---|---|---|
| **Assets** | | |
| Cash and cash equivalents | **$ 852.3** | Increased from proceeds of the convertible debentures and long-term debt and cash from operations, partially offset by increased debt levels, preferred shares repayments and dividends |
| Receivables, net | **63.9** | Increased due to the effect of a stronger USD on the translation of Emera’s foreign subsidiaries and increased cash collateral position on derivative instrument at NSPI |
| Income taxes receivable, net of income taxes payable (current and long-term) | **52.8** | Increased primarily due to the payment of taxes owing for the 2014 tax year by EES and NSPI's required prepayment of taxes for reassessments relating to the timing of tax deductions under dispute with the Canada Revenue Agency |
| Derivative instruments (current and long-term) | **188.6** | Increased primarily due to favourable changes in USD price positions, partially offset by settlements of derivative instruments at NSPI and Emera Energy |
| Regulatory assets (current and long-term) | **96.8** | Increased due to the effect of a stronger USD on the translation of Emera’s foreign subsidiaries and increased regulatory assets related to deferred income taxes, DSM and regulated derivatives, partially offset by amortization at NSPI |
| Property, plant and equipment, net of accumulated depreciation | **577.8** | Increased primarily due to the favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries, increased capital expenditures resulting from major planned outage work at Bridgeport Energy, funding of capital investments at Tiverton Power for 2016 major outage work and increased capital spending at NSPI, partially offset by depreciation |
| Investments subject to significant influence | **117.7** | Increased primarily due to reclassification of Bear Swamp investment credit balance to Other Long-Term Liabilities, outstanding APUC subscription receipts which became eligible for conversion in Q4 2015 (originally recorded in Other Assets), dilution gains in APUC, and increased investments in LIL and M&NP, partially offset by the sale of NWP |
| Available-for-sale investments | **31.6** | Increased primarily due to investment by Emera Reinsurance Limited and favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries |
| Goodwill | **42.6** | Increased due to the effect of a stronger USD on the translation of Emera’s foreign subsidiaries |
| Intangibles | **57.6** | Increased primarily due to investment by Emera Maine in a customer information system and the favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries |
| Other assets (current and long-term) | **115.2** | Increased primarily due to increase in transportation capacity assets in Emera Energy and increased deferred financing costs related to the pending acquisition of TECO Energy, offset by a decrease in APUC subscription receipts which became eligible for conversion in Q4 2015 (now recorded as Investments Subject to Significant Influence) |
| **Liabilities and Equity** | | |
| Short-term debt and long-term debt (including current portion) | **28.3** | Increased primarily due to increased debt levels at NSPI to fund the redemption of preferred stock, issuance of long-term debt by Brunswick Pipeline and the effect of a stronger USD on debt held by foreign subsidiaries, partially offset by repayment of long-term debt |
| Convertible debentures represented by instalment receipts | **727.6** | Increased due to the issuance of convertible debentures related to the pending acquisition of TECO Energy |

| | | |
|---|---|---|
| Deferred income tax liabilities, net of deferred income tax assets | **174.0** | Increased primarily due to the utilization of non-capital loss carryforwards and accelerated tax deductions related to property, plant and equipment at NSPI and Emera Maine |
| Derivative instruments (current and long-term) | **240.5** | Increased primarily due to a new asset management agreement and unfavourable changes in commodity pricing at Emera Energy and unfavourable mark-to-market impacts relating to interest rate and foreign exchange hedges at Brunswick Pipeline |
| Regulatory liabilities (current and long-term) | **168.7** | Increased primarily due to changes in derivative instruments as a result of favourable USD price positions and increased FAM liability at NSPI, partially offset by settlements of derivative instruments at NSPI |
| Pension and post-retirement liabilities (current and long-term) | **(57.8)** | Decreased primarily due to improvement in funded position as a result of greater than expected asset return at NSPI |
| Other liabilities (current and long-term) | **267.7** | Increased primarily due to deferred cost impact of parts and capital work delivered for performance in 2015 by a service provider under long-term service agreements at the New England Gas Generating Facilities, and reclassification of Bear Swamp investment credit balance from Investments Subject to Significant Influence |
| Common stock | **141.1** | Increased primarily due to issuance of common stock for the dividend reinvestment program and purchase of additional ECI shares |
| Accumulated other comprehensive loss | **(484.1)** | Decreased primarily due to the favourable effect of a stronger USD on the translation of Emera's foreign subsidiaries and the amortization of unrecognized pension and post-retirement benefit costs at NSPI |
| Retained earnings | **156.1** | Increased due to net income in excess of dividends paid |
| Non-controlling interest in subsidiaries | **(172.7)** | Decreased due to increased ownership in ECI |

# Developments

## Emera

### Purchase of ECI Outstanding Shares

On November 16, 2015, Emera (Barbados) Holdings No. 2 Inc., (“EBH2”), an indirect wholly-owned subsidiary of Emera, announced its intention to acquire the outstanding shares of ECI. Minority ECI shareholders could elect to receive $23.26 ($33.30 Barbadian dollar (“BBD”)) in cash per common share (“Cash Offer”) or 2.1 Depositary Receipts (“DR”) representing common shares of Emera (“DR Offer”) or a combination of the two Offers. Each Emera DR initially represented one quarter of an Emera common share.

On December 17, 2015, EBH2 acquired approximately 2.6 million ECI Shares, increasing its ownership in ECI to 95.5 per cent from 80.7 per cent. The total consideration paid was $58.7 million, with 92 per cent of shareholders electing the DR Offer and 8 per cent electing the Cash Offer.

On January 8, 2016, the DRs began trading on the Barbados Stock Exchange.

On January 25, 2016, Emera announced EBH2 will proceed to acquire the remaining common shares of ECI from minority shareholders at the same Cash Offer and DR Offer, described above, by way of an amalgamation between ECI and a wholly-owned subsidiary of EBH2.

ECI is also proposing to amend the terms of its 5.5 per cent cumulative preferred shares to make them redeemable at a 20 per cent premium to their issuance price. An ECI shareholders’ meeting to vote on the amalgamation and preferred share amendment will take place on February 24, 2016.

**Pending Acquisition of TECO Energy**

On September 4, 2015, the Company announced a definitive agreement (“the acquisition agreement”) for Emera to acquire TECO Energy (“the Transaction”) (NYSE:TE). TECO Energy shareholders will receive $27.55 USD per common share in cash, which represents an aggregate purchase price of approximately $10.4 billion USD and includes the assumption of approximately $3.9 billion USD of debt.

TECO Energy is an energy-related holding company with regulated electric and gas utilities in Florida and New Mexico. TECO Energy’s holdings include: Tampa Electric, an integrated regulated electric utility which serves more than 700,000 customers in West Central Florida; Peoples Gas System, a regulated gas distribution utility which serves more than 350,000 customers across Florida; and New Mexico Gas Co., a regulated gas distribution utility which serves more than 510,000 customers across New Mexico.

Upon completion of the Transaction, Emera will have over $26 billion of assets and more than 2.4 million electric and gas customers. Emera has fully committed $6.5 billion USD bridge facilities in place, and financed a portion of the pending acquisition through the sale of $2.185 billion convertible unsecured subordinated debentures, which are described below. The balance of the permanent financing of the Transaction is expected to be obtained before or after closing, from one or more capital market offerings, including debt and preferred equity, as well as from internally generated sources. On October 16, 2015, Emera permanently reduced the USD bridge facilities in the amount of $588.3 million USD with the proceeds of the first instalment of the convertible debentures and the proceeds from the Bear Swamp financing discussed below.

The closing of the Transaction is expected to occur mid-2016. It is subject to certain regulatory and government approvals, including approval by the New Mexico Public Regulation Commission, the Committee on Foreign Investment in the United States, and the satisfaction of closing conditions. Below is a summary of the approvals received to date:

- Shareholder approval on December 3, 2015;
- FERC approval on January 21, 2016;
- Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

On December 14, 2015, the New Mexico Public Regulation Commission set a hearing to begin on May 23, 2016 for the joint application of the change in control of New Mexico Gas Co. effected by the Transaction.

**Convertible Debentures Represented By Instalment Receipts**

To finance a portion of the pending acquisition of TECO Energy, Emera, through a direct wholly owned subsidiary (the “Selling Debentureholder”), on September 28, 2015, completed the sale of $1.9 billion aggregate principal amount of 4.0% convertible unsecured subordinated debentures, represented by instalment receipts (the “Debentures” or the “Debenture Offering”).

On October 2, 2015, in connection with the Debenture Offering, the underwriters fully exercised an over-allotment option and purchased an additional $285 million aggregate principal amount of Debentures at the Debenture Offering price. The sale of the additional Debentures brought the aggregate proceeds of the Debenture Offering to $2.185 billion, assuming payment of the final instalment.

The Debentures were sold on an instalment basis at a price of $1,000 per Debenture, of which $333 was paid on closing of the Debenture Offering and the remaining $667 (the “Final Instalment”) is payable on a date (“Final Instalment Date”) to be fixed following satisfaction of conditions precedent to the closing of the acquisition of TECO Energy.

Prior to the Final Instalment Date, the Debentures are represented by instalment receipts. The instalment receipts began trading on the Toronto Stock Exchange (“TSX”) on September 28, 2015 under the symbol “EMA.IR”. The Debentures will not be listed. The Debentures will mature on September 29, 2025 and bear interest at an annual rate of four per cent per $1,000 principal amount of Debentures until and including the Final Instalment Date, after which the interest rate will be 0 per cent. Based on the first instalment of $333 per $1,000 principal amount of Debentures, the effective annual yield to and including the Final Instalment Date is 12 per cent, and the effective annual yield thereafter is 0 per cent.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the Debentures remained outstanding and continued to accrue interest until and including such date (the "Make-Whole Payment"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering. Under the terms of the instalment receipt agreement, Emera agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Company will at all times hold (on a consolidated basis) short-term USD investment grade securities or have cash on hand of not less than the aggregate amount of the first instalment paid on the closing of the Debenture Offering and the exercise of the over-allotment option, in the event of a mandatory redemption.

At the option of the holders and provided that payment of the Final Instalment has been made, each Debenture will be convertible into common shares of Emera at any time after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $41.85 per common share. This is a conversion rate of 23.8949 common shares per $1,000 principal amount of Debentures, subject to adjustment in certain events.

Prior to the Final Instalment Date, the Debentures may not be redeemed by the Company, except that Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions precedent to the closing of the acquisition of TECO Energy will not be satisfied; (ii) termination of the acquisition agreement; and (iii) April 24, 2017, if notice of the Final Instalment Date has not been given to holders on or before April 21, 2017. Upon any such redemption, the Company will pay for each Debenture: (i) $333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the instalment receipt in satisfaction of the Final Instalment. In addition, after the Final Instalment Date, any Debentures not converted may be redeemed by Emera at a price equal to their principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date.

At maturity, Emera will repay the principal amount of any Debentures not converted and remaining outstanding in cash. Emera has the right to satisfy the obligation to repay the principal amount due in common shares, which will be valued at 95 per cent of the weighted-average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

The proceeds of the first instalment and the overallotment of the Debenture Offering were $727.6 million, or $681.4 million net of issue costs, and are held and invested in short-term USD investment grade securities. The convertible debentures represented by instalment receipts are classified as a current liability on the Consolidated Balance Sheets as the pending acquisition of TECO Energy is expected to close in fiscal 2016. The mark-to-market effect related to the translation of the US foreign currency to Canadian currency is recorded in income, but not reflected in adjusted net income.

The net proceeds of the final instalment payment of the Debenture Offering are expected to be, in aggregate, approximately $1.4 billion and will be used, together with the net proceeds of the first instalment payment, to finance, directly or indirectly, the pending acquisition of TECO Energy and other acquisition related costs. To mitigate the foreign currency translation risk associated with the final instalment Emera entered into USD denominated forward contracts, which are recorded on the Consolidated Balance Sheets. The mark-to-market effect on these hedges is reported in the income statement and impacts income, but is not reflected in adjusted income.

Approximately $22.1 million ($15.2 million after-tax) in interest expense associated with the Debentures was recognized in Q4 2015 and $22.7 million ($15.7 million after-tax) was incurred during fiscal 2015 (2014 – nil).

### Increase in Common Dividend

On August 10, 2015, Emera's Board of Directors approved an increase in the annual common share dividend rate from $1.60 to $1.90. The first payment was effective November 16, 2015.

### Maritime Link Project

On March 6, 2015, NSPML entered into the third of the Maritime Link Project's three major contracts: construction of approximately 400 kilometres of transmission lines in the provinces of Newfoundland and Labrador and Nova Scotia.

On April 9, 2015, NSPML and the Assembly of Nova Scotia Mi'kmaq Chiefs signed a Socio-Economic Agreement for the Maritime Link Project. Under this agreement, NSPML will support ongoing engagement and commitments made during the Environmental Assessment process, including Mi'kmaq participation in environmental monitoring and employment and business opportunities for Mi'kmaq people.

## Emera Maine

### Return on Equity ("ROE") Complaints

On March 3, 2015, the FERC affirmed its June 19, 2014 order approving an ROE on transmission assets of 10.57 per cent for the period October 1, 2011 to December 31, 2012. This order is in respect of the ROE complaint filed with the FERC by the Attorney General of Massachusetts and other parties on September 30, 2011. The March 3, 2015 order is subject to appeal, and a decision is not expected until Q1 2016 at the earliest.

## Recent Financing Activity

### Emera

On July 3, 2015, Emera announced it would not redeem the 6,000,000 Cumulative 5-Year Rate Reset First Preferred Shares, Series A Shares ("the Series A Shares").

On August 17, 2015, Emera announced that 2,135,364 of its 6,000,000 issued and outstanding Series A Shares were tendered for conversion, on a one-for-one basis into Cumulative Floating Rate First Preferred Shares, Series B (the "Series B Shares"). As a result of the conversion, Emera has 3,864,636 Series A Shares and 2,135,364 Series B Shares issued and outstanding. The holders of Series B Shares will be entitled to receive floating rate cumulative preferred cash dividends, as and when declared by the Board of Directors. The dividends are payable quarterly in the amount per share determined by multiplying the applicable quarterly floating dividend rate, which is the sum of the three-month Government of Canada T-bill Rate on the applicable reset date plus 1.84 per cent, by $25.00.

### NSPI

NSPI Series I $70 million 8.40 per cent medium-term notes ("MTN") matured on October 23, 2015 and were repaid.

On October 15, 2015, NSPI redeemed all of its outstanding Cumulative Redeemable First Preferred Shares, Series D for a redemption price of $25.00 per share for a total of $135 million.

On April 30, 2015, NSPI completed the issuance of $175 million Series AA MTN. The Series AA notes bear interest at a rate of 3.612 per cent per annum until May 1, 2045. The proceeds of the note offering were used for general corporate purposes, including the repayment of maturing corporate term debt.

**Brunswick Pipeline**

On February 18, 2015, Brunswick Pipeline completed a senior secured financing consisting of a $250 million non-revolving term credit facility bearing interest at bankers' acceptances rates plus 1.75 per cent and expiring on February 18, 2019. The proceeds were used to reduce borrowings under Emera's revolver, which was previously used to finance the maturity and repayment of an MTN in October 2014.

**Emera Energy**

On October 8, 2015, Bear Swamp refinanced its $125 million USD bank debt that was due to mature in 2017 and issued $400 million USD in senior secured 10-year bonds, with $375 million USD at a fixed rate of 4.89 per cent, and $25 million USD at a floating rate of LIBOR plus 2.70 per cent. The proceeds of this financing were used to repay existing debt and provide working capital to the joint venture, with the remainder shared equally between Emera and its joint venture partner. After fees and expenses, Emera received a $178.7 million ($137.3 million USD) non-taxable distribution in Q4 2015.

## Appointments

**Executive**

On January 15, 2016, Greg Blunden was appointed Chief Financial Officer ("CFO") of Emera, effective March 1, 2016. Mr. Blunden has held financial leadership roles at Emera, Emera Maine and NSPI. Most recently, Mr. Blunden was Vice President, Corporate Strategy & Planning.

On January 15, 2016, Emera's current CFO, Scott Balfour, was appointed Chief Operating Officer, Northeast and Caribbean, effective March 1, 2016. Mr. Balfour will provide senior executive leadership for Emera's existing operations, including NSPI, Emera Energy, Emera Maine, Emera Caribbean, Emera Brunswick Pipeline and Emera Utility Services.

On January 15, 2016, Wayne O'Connor was appointed Vice President, Corporate Strategy & Planning for Emera, effective March 1, 2016. Mr. O'Connor will coordinate Emera's planning and strategy development efforts to grow and expand the Company's business. Previously, he was Executive Vice-President of Operations at NSPI.

On September 22, 2015, Rob Bennett was appointed President and Chief Executive Officer of Emera U.S. Inc., a wholly owned subsidiary of Emera, to lead the integration of TECO Energy. Previously, Mr. Bennett had been the Chief Operating Officer, Eastern Canada.

On August 31, 2015, Roman Coba was appointed Chief Information Officer of Emera.

# OUTSTANDING COMMON STOCK DATA

| **Common stock**<br>**Issued and outstanding:** | millions of shares | millions of Canadian dollars | |
|---|---|---|---|
| December 31, 2013 | 132.89 | $ | 1,703.0 |
| Issuance of common stock | 8.66 | | 242.8 |
| Issued for cash under Purchase Plans at market rate | 1.97 | | 66.6 |
| Discount on shares purchased under Dividend Reinvestment Plan | - | | (3.0) |
| Options exercised under senior management stock option plan | 0.26 | | 6.2 |
| Employee Share Purchase Plan | - | | 0.8 |
| December 31, 2014 | 143.78 | $ | 2,016.4 |
| Issuance of common stock (1) | 1.25 | | 53.7 |
| Issued for cash under Purchase Plans at market rate | 2.10 | | 88.3 |
| Discount on shares purchased under Dividend Reinvestment Plan | - | | (4.1) |
| Options exercised under senior management stock option plan | 0.08 | | 2.3 |
| Employee Share Purchase Plan | - | | 0.9 |
| **December 31, 2015** | **147.21** | **$** | **2,157.5** |

(1) On December 17, 2015, Emera issued 1.25 million common shares to facilitate the creation and issuance of 5.0 million depositary receipts in connection with the ECI share acquisition. The depositary receipts are listed on the Barbados Stock Exchange.

As at January 29, 2016, the amount of issued and outstanding common shares was 147.3 million. The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended December 31, 2015 was 146.8 million (2014 – 144.2 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2015 was 145.8 million (2014 – 143.2 million).

# NSPI

## Overview

NSPI was created in 1992 through the privatization of the Crown corporation Nova Scotia Power Corporation ("NSPC"). NSPI is a fully-integrated regulated electric utility and is the primary electricity supplier in Nova Scotia, Canada. NSPI has $4.6 billion of assets and provides electricity generation, transmission and distribution services to approximately 506,000 customers. NSPI owns 2,483 MW of generating capacity, of which approximately 50 per cent is coal-fired; 28 per cent of which is natural gas and/or oil; 19 per cent of which is hydro and wind and 3 per cent of which is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPPs own and operate 496 MW of wind and biomass fueled generation capacity, which will increase to 552 MW in 2016. NSPI also owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities. NSPI has a workforce of approximately 1,700 people.

NSPI is a public utility as defined in the Public Utilities Act (Nova Scotia) ("Act") and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings from time to time at its request or at the UARB's request.

NSPI is regulated under a cost-of-service model, with rates established to recover prudently incurred costs of providing electricity service to customers, and to provide an appropriate return to investors. NSPI's target regulated return on equity ("ROE") range for 2015 and 2016 is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40.0 per cent.

NSPI has a fuel adjustment mechanism ("FAM"), approved by the UARB, allowing NSPI to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between prudently incurred fuel for generation and purchased power and certain fuel-related costs ("Fuel Costs") and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

A settlement agreement, approved by the UARB in November 2014, resulted in approximately $56.0 million of the outstanding FAM regulatory asset balance from the prior year being collected in 2015. Residential customers did not experience a rate increase in 2015, as the FAM recovery of approximately $56.0 million was offset with the removal of charges previously included in NSPI billings. The charges were on behalf of Efficiency Nova Scotia, a program run by the Province of Nova Scotia and regulated by the UARB. Certain industrial customer classes experienced rate increases of approximately 1.5 per cent in 2015.

On December 21, 2015, the UARB approved NSPI's setting of the 2016 base cost of fuel and its recovery of prior period unrecovered fuel related costs as submitted in NSPI's August and November 2015 filings. The recovery of these costs will begin January 1, 2016. The approved customer rates reset the base cost of fuel rate for 2016 and seek to recover $13.7 million of prior years' unrecovered Fuel Costs in 2016. This results in a combined rate decrease for customers of approximately 1 per cent.

In December 2015, the Electricity Plan Implementation (2015) Act ("the Electricity Plan Act") was enacted by the Province of Nova Scotia. Further information is included in the NSPI Regulated Fuel Adjustment Mechanism and Fixed Cost Deferrals Section.

Although the market in Nova Scotia is otherwise mature, the transformation of energy supply to lower emission sources has driven organic growth within NSPI as new investments have been made in renewable generation and system reliability projects.

The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix. The most recent target, for years 2015 through 2019, is 25 per cent of electrical energy which will be derived from renewable sources. This target was met for 2015, with 27 per cent of NSPI's generation mix derived from renewable sources. In 2020, the target is 40 per cent of electrical energy to be derived from renewable sources.

# Review of 2015

**NSPI Net Income**

| For the<br>millions of Canadian dollars (except per share amounts) | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| **Operating revenues – regulated** | **$ 338.5** | $ 332.7 | **$ 1,417.3** | $ 1,348.2 | $ 1,334.9 |
| Regulated fuel for generation and purchased power (1) | **132.4** | 127.4 | **542.8** | 511.7 | 556.9 |
| Regulated fuel adjustment mechanism and fixed cost deferrals | **10.3** | 5.7 | **41.6** | 46.6 | (40.8) |
| Operating, maintenance and general | **66.2** | 68.9 | **298.1** | 273.6 | 272.3 |
| Provincial grants and taxes | **9.7** | 9.6 | **38.5** | 38.3 | 37.7 |
| Depreciation and amortization | **52.2** | 53.0 | **206.5** | 204.0 | 213.8 |
| Total operating expenses | **270.8** | 264.6 | **1,127.5** | 1,074.2 | 1,039.9 |
| **Income from operations** | **67.7** | 68.1 | **289.8** | 274.0 | 295.0 |
| Other expenses net (2) | **-** | 0.7 | **5.7** | 5.0 | 7.1 |
| Interest expense, net | **31.3** | 29.9 | **122.1** | 116.5 | 119.6 |
| **Income before provision for income taxes** | **36.4** | 37.5 | **162.0** | 152.5 | 168.3 |
| Income tax expense (recovery) | **(6.4)** | 5.5 | **23.4** | 19.7 | 34.4 |
| Net income of Nova Scotia Power Inc. | **42.8** | 32.0 | **138.6** | 132.8 | 133.9 |
| Preferred stock dividends (3) | **2.7** | 1.9 | **8.7** | 7.9 | 7.9 |
| **Contribution to consolidated net income** | **$ 40.1** | $ 30.1 | **$ 129.9** | $ 124.9 | $ 126.0 |
| **Contribution to consolidated earnings per common share** | **$ 0.27** | $ 0.21 | **$ 0.89** | $ 0.87 | $ 0.95 |
| | | | | | |
| EBITDA | **$ 119.9** | $ 120.4 | **$ 490.6** | $ 473.0 | $ 501.7 |

(1) Regulated fuel for generation and purchased power includes affiliate transactions and proceeds from the sale of natural gas.
(2) Other expenses, net is included in "Other income (expenses), net" on the Consolidated Statements of Income.
(3) Preferred stock dividends are included in "Non-controlling interest in subsidiaries" on the Consolidated Statements of Income. In Q4 2015, NSPI redeemed its preferred shares.

NSPI's contribution to consolidated net income increased $10.0 million to $40.1 million in Q4 2015 compared to $30.1 million in Q4 2014. For the year ended December 31, 2015, NSPI's contribution to consolidated net income increased $5.0 million to $129.9 million in 2015 compared to $124.9 million in 2014.

Highlights of the changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2013** | | **$ 126.0** |
| Increased electric margin primarily due to increased non-fuel electric revenues across all customers groups as a result of increased electricity pricing, partially offset by the FAM audit disallowance | | 15.8 |
| Decreased fixed cost deferrals primarily due to an increase in the non-fuel revenues and lower depreciation and amortization | | (43.2) |
| Decreased depreciation and amortization primarily due to reductions in regulatory amortization (see Regulatory Amortization section below for explanation) | | 9.8 |
| Decreased interest expense, net primarily due to lower levels of long-term debt | | 3.1 |
| Decreased income tax expense primarily due to increased tax deductions related to higher pension contributions for 2014, decreased income before provision for income taxes and decreased non-deductible regulatory amortization, partially offset by a non-recurring change in unrecognized tax benefits in 2013 due to the enactment of tax legislation related to preferred stock dividends | | 14.7 |
| Other, net (1) | | (1.3) |
| **Contribution to consolidated net income – 2014** | **$ 30.1** | **$ 124.9** |
| Increased electric margin (see Electric Margin section below for explanation) | 0.5 | 13.0 |
| Increased fixed cost deferrals year-over-year primarily due to the new DSM regulatory deferral commencing in 2015, partially offset by an increase in the amount of non-fuel revenues deferred compared to 2014 | (1.7) | 30.5 |
| Decreased OM&G expenses quarter-over-quarter primarily due to non-recurring 2014 expenses and increased overhead credits on capital projects, partially offset by higher pension and DSM costs; year-over-year increase is primarily due to increased DSM program costs as a results of legislation, effective January 1, 2015, requiring NSPI to purchase electricity efficiency and conservation activities and higher pension costs, partially offset by lower storm costs | 2.7 | (24.5) |
| Increased interest expense, net primarily due to lower interest revenues related to FAM and fixed cost deferrals and higher debt levels | (1.4) | (5.6) |
| Decreased income tax expense quarter-over-quarter primarily due to a legislated change by the Province of Nova Scotia to the deferred tax treatment of South Canoe and Sable wind farms resulting in prior period deferred income taxes being recorded as regulatory assets in Q4 2015; year-over-year increase primarily due to increased income before provision for income taxes | 11.9 | (3.7) |
| Other, net (1) | (2.0) | (4.7) |
| **Contribution to consolidated net income – 2015** | **$ 40.1** | **$ 129.9** |

(1) Amounts exclude variances included in the calculation of electric margin.

## Operating Revenues – Regulated

NSPI's Operating Revenues – regulated include sales of electricity and other services as summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Electric revenues | **$ 333.5** | $ 324.9 | **$ 1,389.1** | $ 1,319.2 | $ 1,304.3 |
| Other revenues | **5.0** | 7.8 | **28.2** | 29.0 | 30.6 |
| Operating revenues – regulated | **$ 338.5** | $ 332.7 | **$ 1,417.3** | $ 1,348.2 | $ 1,334.9 |

## Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population, weather, and DSM activities. Residential and commercial electricity sales are seasonal, with Q1 being the strongest period, reflecting colder weather and fewer daylight hours in the winter.

NSPI's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other electric revenues consist primarily of sales to municipal electric utilities and revenues from street lighting.

Electric sales volumes are summarized in the following tables by customer class:

**Q4 Electric Sales Volumes**
Gigawatt hours ("GWh")

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Residential | **1,075** | 1,083 | 1,173 |
| Commercial | **757** | 767 | 811 |
| Industrial | **592** | 630 | 635 |
| Other | **82** | 75 | 87 |
| Total | **2,506** | 2,555 | 2,706 |

**Annual Electric Sales Volumes**
GWh

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Residential | **4,484** | 4,370 | 4,394 |
| Commercial | **3,134** | 3,092 | 3,148 |
| Industrial | **2,457** | 2,513 | 2,605 |
| Other | **337** | 312 | 320 |
| Total | **10,412** | 10,287 | 10,467 |

Electric revenues are summarized in the following tables by customer class:

**Q4 Electric Revenues**
millions of Canadian dollars

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Residential | **$ 170.7** | $ 165.7 | $ 173.5 |
| Commercial | **100.0** | 97.3 | 100.1 |
| Industrial | **51.1** | 50.3 | 55.4 |
| Other | **11.7** | 11.6 | 13.0 |
| Total | **$ 333.5** | $ 324.9 | $ 342.0 |

**Annual Electric Revenues**
millions of Canadian dollars

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Residential | **$ 716.0** | $ 669.3 | $ 654.0 |
| Commercial | **410.0** | 387.3 | 383.9 |
| Industrial | **213.8** | 213.9 | 218.0 |
| Other | **49.3** | 48.7 | 48.4 |
| Total | **$ 1,389.1** | $ 1,319.2 | $ 1,304.3 |

Electric revenues increased $8.6 million to $333.5 million in Q4 2015 compared to $324.9 million in Q4 2014. For the year ended December 31, 2015, electric revenues increased $69.9 million to $1,389.1 million compared to $1,319.2 million in the same period in 2014. Highlights of the changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Electric revenues – 2013** | | **$ 1,304.3** |
| Increased electricity pricing effective January 1, 2014 | | 37.9 |
| Decreased commercial and residential sales volumes, in part due to weather | | (12.5) |
| Decreased industrial sales volume | | (9.4) |
| Other | | (1.1) |
| **Electric revenues – 2014** | **$ 324.9** | **$ 1,319.2** |
| Increased fuel related electricity pricing effective January 1, 2015 | 13.4 | 56.0 |
| Decreased commercial and residential sales volumes as a result of decreased load quarter-over-quarter; increased commercial and residential sales volumes year-over-year primarily due to weather and load growth earlier in the year | (4.1) | 19.9 |
| Decreased industrial sales volume | (0.6) | (5.2) |
| Other | (0.1) | (0.8) |
| **Electric revenues – 2015** | **$ 333.5** | **$ 1,389.1** |

## Regulated Fuel for Generation and Purchased Power

### Capacity

To ensure reliability of service, NSPI must maintain a generating capacity greater than firm peak demand. The total NSPI-owned generation capacity is 2,483 MW, which is supplemented by 496 MW contracted with IPPs and the Community Feed-In Tariff ("COMFIT") participants. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area and the Northeast Power Coordinating Council.

NSPI facilities continue to rank among the best in Canada on performance indicators. The high availability and capability of low cost thermal generating stations provide lower-cost energy to customers. In 2015, thermal plant availability was 87.9 per cent compared to 84.2 per cent in 2014. NSPI's four-year average for thermal plant availability is 85.1 per cent. While this availability is in line with industry standards, it is particularly significant, as the NSPI coal fleet has a higher capacity factor and better forced outage rate than the standard for its class. In addition, the Company has seen performance improvements in 2015, despite the effects of renewable integration.

**Q4 Production Volumes**
GWh

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Coal and petcoke | **1,534** | 1,777 | 1,842 |
| Natural gas | **354** | 186 | 423 |
| Oil | **8** | 9 | 33 |
| Purchased power – other | **121** | 126 | 57 |
| Total non-renewables | **2,017** | 2,098 | 2,355 |
| Wind and hydro – renewables | **228** | 391 | 333 |
| Biomass – renewables | **63** | 62 | 67 |
| Purchased power – renewables | **434** | 255 | 214 |
| Total renewables | **725** | 708 | 614 |
| Total production volumes | **2,742** | 2,806 | 2,969 |

**Annual Production Volumes**
GWh

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Coal and petcoke | **6,364** | 6,609 | 7,098 |
| Natural gas | **1,302** | 1,468 | 1,317 |
| Oil | **265** | 153 | 89 |
| Purchased power – other | **428** | 353 | 491 |
| Total non-renewables | **8,359** | 8,583 | 8,995 |
| Wind and hydro – renewables | **1,275** | 1,357 | 1,234 |
| Biomass – renewables | **206** | 258 | 130 |
| Purchased power – renewables | **1,289** | 849 | 845 |
| Total renewables | **2,770** | 2,464 | 2,209 |
| Total production volumes | **11,129** | 11,047 | 11,204 |

**Q4 Average Fuel Costs**

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Dollars per megawatt hour ("MWh") | **$ 48** | $ 45 | $ 49 |

**Annual Average Fuel Costs**

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Dollars per MWh | **$ 49** | $ 46 | $ 50 |

Average unit Fuel Costs increased in Q4 2015 compared to Q4 2014 primarily due to generation costs associated with the COMFIT program and decreased NSPI-owned hydro generation partially due to the largest hydro site undergoing a planned overhaul this quarter. These costs are partially offset by favourable commodity pricing. Year-over-year, average unit Fuel Costs increased in 2015 compared to the same period in 2014 primarily due to generation costs associated with the COMFIT program and increased load, partially offset by favourable commodity pricing.

NSPI's Fuel Costs are affected by commodity prices and generation mix which is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on stream first (after renewable energy from independent power producers, including COMFIT participants), such that the incremental cost of production increases as sales volumes increase. Generation mix may also be affected by plant outages, availability of renewable generation, plant performance and compliance with environmental standards and regulations.

Historically, coal and petcoke have the lowest per unit fuel cost, after NSPI-owned regulated hydro and wind, which have no fuel cost component. Purchased power, natural gas, oil and biomass have the next lowest fuel cost, depending on the relative pricing of each.

The generation mix is transforming with the addition of new non-dispatchable renewable energy sources such as wind, which typically has a higher cost per megawatt hour ("MWh").

A large portion of NSPI's fuel supply comes from international suppliers and is subject to commodity price and foreign exchange risk. NSPI seeks to manage this risk through the use of financial hedging instruments and physical contracts and utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. Foreign exchange risk is managed through forward and swap contracts. Fuel contracts may also be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. NSPI has a FAM that enables the Company to seek recovery of Fuel Costs to further manage this risk.

Regulated fuel for generation and purchased power increased $5.0 million to $132.4 million in Q4 2015 compared to $127.4 million in Q4 2014. For the year ended December 31, 2015, regulated fuel for generation and purchased power increased $31.1 million to $542.8 million compared to $511.7 million in 2014. Highlights of the changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Regulated fuel for generation and purchased power – 2013** | | **$ 556.9** |
| Decreased commodity prices | | (29.0) |
| Changes in generation mix and plant performance | | (11.1) |
| Decreased sales volumes | | (8.8) |
| Increased hydro and NSPI-owned wind production | | (8.1) |
| Changes in solid fuel mix | | 14.4 |
| Other | | (2.6) |
| **Regulated fuel for generation and purchased power – 2014** | **$ 127.4** | **$ 511.7** |
| Decreased commodity prices | (6.6) | (38.3) |
| Changes in generation mix and plant performance | 8.5 | 51.1 |
| Increased (decreased) sales volumes | (1.5) | 10.6 |
| Decreased hydro and NSPI-owned wind production | 5.0 | 3.0 |
| Other | (0.4) | 4.7 |
| **Regulated fuel for generation and purchased power – 2015** | **$ 132.4** | **$ 542.8** |

## Regulated Fuel Adjustment Mechanism ("FAM") and Fixed Cost Deferrals

### Regulated Fuel Adjustment Mechanism and FAM Regulatory Deferral

NSPI has a Regulated Fuel Adjustment Mechanism which enables the Company to seek recovery of Fuel Costs through regularly scheduled rate adjustments. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

On December 21, 2015, the UARB approved NSPI's setting of the 2016 base cost of fuel rates and its recovery of prior period unrecovered fuel related costs as submitted in NSPI's filings. The recovery of these costs will begin January 1, 2016. The approved customer rates reset the base cost of fuel rate for 2016 and seek to recover $13.7 million of prior years' unrecovered Fuel Costs in 2016. This results in a combined average rate decrease for NSPI customers of approximately 1 per cent.

On December 18, 2015, the Electricity Plan Act was enacted by the Province of Nova Scotia. The Electricity Plan Act requires NSPI to file a three-year rate plan for Fuel Costs in Q1 2016 and to file a three-year general rate application to change non-fuel rates by April 30, 2016, if required by NSPI. The primary goal of the Electricity Plan Act is to provide rate stability over those years. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates during this period will be deferred to a FAM regulatory asset or liability and recovered from or returned to customers subsequent to 2019.

The Electricity Plan Act directs NSPI to apply non-fuel revenues in excess of NSPI's approved range of return in 2015 and 2016 to the FAM, which will be reserved to be applied in the 2017 to 2019 period. In addition, the financial benefit resulting from a change in the recognition of tax benefits for the South Canoe and Sable Wind Projects is to be reserved to be applied to the FAM in the 2017 to 2019 period. The exception to this direction is to apply a sufficient amount of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016 that would have been otherwise required. This amount totals $4.6 million. As a result, as at December 31, 2015, NSPI has deferred $4.6 million of excess non-fuel revenues to 2016 and $40.1 million of excess non-fuel revenues for the periods 2017 to 2019.

In November 2014, the UARB approved a settlement agreement that has resulted in $56.0 million of the 2014 outstanding FAM balance being collected in 2015. The settlement agreement also reduced the outstanding FAM balance of $86.1 million by $38.2 million through an offset from the amount owing to customers as a result of an agreement to allocate non-fuel revenues above NSPI's allowed range of return to the FAM balance, such that the December 31, 2014 FAM regulatory asset was $47.9 million.

Through a related settlement agreement with stakeholders approved in December 2014, NSPI agreed to apply non-fuel revenues above that required to achieve its approved range of return to reduce the FAM deferral account. This was effective as of January 1, 2015, until the next GRA approval or similar process where non-fuel rates are adjusted. This settlement agreement required NSPI to contribute a minimum of $41.3 million to the FAM deferral account by the end of 2015.

As at December 31, 2015, NSPI had exceeded the minimum required contribution of $41.3 million through the $38.2 million contributed in 2014, referred to above, and an additional $44.7 million applied in 2015. Of the $44.7 million applied in 2015, $18.3 million relates to changes to the South Canoe and Sable Wind Projects tax treatment.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. On July 2, 2014, the FAM audit findings and recommendations relating to fiscal 2012 and 2013 were publicly released, and on January 20, 2015, the UARB disallowed $6.0 million of 2012 and 2013 fuel-related costs, which included interest of $0.9 million. The disallowance resulted in a reduction in the amount of FAM deferral in 2014 and resulted in an after-tax impact to 2014 net income of $3.3 million. The audit for fiscal 2014 and 2015 is currently underway.

The FAM in the Statements of Income includes the effect of Fuel Costs in both the current and preceding years, specifically:

- The difference between actual Fuel Costs and amounts recovered from customers in the current year. This amount is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities"; and
- The recovery from (rebate to) customers of under (over) recovered Fuel Costs from prior years.

The FAM regulatory asset (liability) includes amounts recognized as a regulated fuel adjustment mechanism and associated interest that is included in "Interest expense, net" on the Consolidated Statements of Income. Details of the FAM regulatory asset (liability), classified in "Regulatory assets or Regulated liabilities" on the Consolidated Balance Sheets, are summarized in the following table:

| millions of Canadian dollars | | **2015** | | 2014 |
|---|---|---|---|---|
| **FAM regulatory asset – Balance as at January 1** | **$** | **47.9** | **$** | **86.4** |
| Under (over) recovery of current year Fuel Costs | | 24.1 | | (1.3) |
| Rebate to (recovery from) customers of prior years' Fuel Costs | | (56.0) | | - |
| FAM audit disallowance, including interest adjustment | | - | | (6.0) |
| Application of non-fuel revenues | | (44.7) | | (38.2) |
| Interest on FAM balance | | 0.4 | | 7.0 |
| **FAM regulatory asset (liability) – Balance as at December 31** | **$** | **(28.3)** | **$** | **47.9** |

Of the $44.7 million non-fuel revenues applied in 2015, $40.1 million is to be applied to the FAM during the 2017 to 2019 period and $4.6 million will be applied in 2016.

**Regulated Fixed Cost Deferrals and Fixed Cost Recovery Deferral Regulatory Assets**

NSPI has the following regulatory assets arising from UARB approved fixed cost deferral mechanisms:

DSM Deferral

In April 2014, the Government of Nova Scotia announced new energy efficiency legislation to remove a previous charge for conservation and efficiency programs from power bills of Nova Scotia customers effective January 1, 2015. In addition, the legislation requires NSPI to purchase electricity efficiency and conservation activities ("Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The Program Costs were set for 2015 at $35.0 million and have been deferred as a regulatory asset and recoverable from customers over an eight-year period beginning in 2016. In August 2015, the UARB approved a budget of $102.0 million for the three-year period of 2016 through 2018. The Electricity Plan Act has placed a cap of $34.0 million on the 2019 DSM spending. The 2016 DSM cost of $24.7 million will not be deferred. A decision of the timing of the cost recovery for 2017 through 2019 will be made at a future date.

The Program Costs are recorded in "OM&G", with an offsetting credit in "Regulated fuel adjustment mechanism and fixed cost deferrals" on Emera's Consolidated Income Statements, with no effect on net earnings, with the exception of interest on the balance.

Details of the DSM regulatory asset, classified in "Regulatory assets" on the Consolidated Balance Sheets, are summarized in the following table:

| millions of Canadian dollars | | **2015** |
|---|---|---|
| **DSM regulatory asset – Balance as at January 1** | **$** | **-** |
| Current period Program Costs | | 35.0 |
| Interest on DSM balance | | 1.4 |
| **DSM regulatory asset – Balance as at December 31** | **$** | **36.4** |

2013/2014 Rate Stabilization Fixed Cost Recovery Deferral

In December 2012, the UARB approved a deferral of recovery of certain fixed costs for fiscal 2013 and 2014 as part of a rate stabilization plan. As previously noted above under the Regulated Fuel Adjustment Mechanism, the resulting regulatory liability at the end of 2014 of $38.2 million was applied against the FAM regulatory asset balance in 2014 and is included in the application of non-fuel revenues line in the table above.

## Electric Margin

NSPI distinguishes electric revenues related to the recovery of Fuel Costs ("fuel electric revenues") from revenues related to the recovery of non-fuel costs ("non-fuel electric revenues") because the FAM effectively seeks to recover all prudently incurred fuel costs, and consequently, Fuel Costs and revenues related thereto (Fuel Electric Revenues) do not have a material effect on NSPI's electric margin or net income.

Electric margin is influenced primarily by revenues relating to non-fuel costs. NSPI's customer classes contribute differently to the Company's non-fuel electric revenues, with residential and commercial customers contributing more than industrial customers under current rates. Accordingly, changes in residential and commercial load, largely due to the effects of weather, from general economic conditions and from DSM have the largest effect on non-fuel electric revenues and electric margin. Changes in industrial load, which are generally due to economic conditions, have less of an effect on non-fuel electric revenues than would a similar volume change in residential and commercial load.

The addition of new generation sources to meet legislated greenhouse gas emission reductions and renewable generation requirements is among the drivers increasing NSPI's fixed costs. Electric margin, which represents the revenues available to cover these costs, has increased in a corresponding manner.

Operating revenues are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014(1) | 2013(1) |
| Fuel electric revenues – current year | **$ 123.7** | $ 124.2 | **$ 518.5** | $ 512.5 | $ 488.7 |
| Fuel electric revenues – recovery of preceding years | **13.4** | - | **56.0** | - | 29.8 |
| Non-fuel electric revenues | **196.4** | 200.7 | **814.6** | 806.7 | 785.8 |
| Other revenues | **5.0** | 7.8 | **28.2** | 29.0 | 30.6 |
| Operating revenues | **$ 338.5** | $ 332.7 | **$ 1,417.3** | $ 1,348.2 | 1,334.9 |

Electric margin is summarized in the following table:

| | | | | | |
|---|---|---|---|---|---|
| Fuel electric revenues – current year | **$ 123.7** | $ 124.2 | **$ 518.5** | $ 512.5 | $ 488.7 |
| Fuel electric revenues – recovery of preceding years | **13.4** | - | **56.0** | - | 29.8 |
| Total fuel electric revenues | **137.1** | 124.2 | **574.5** | 512.5 | 518.5 |
| Regulated fuel for generation and purchased power | **(132.4)** | (127.4) | **(542.8)** | (511.7) | (556.9) |
| Regulated fuel adjustment mechanism | **(4.4)** | (1.5) | **(31.9)** | (6.4) | 37.8 |
| Fuel-related foreign exchange gain (loss) (2) | **(0.3)** | (0.1) | **0.2** | 0.5 | 0.6 |
| **Net fuel revenue (expense)** | **-** | (4.8) | **-** | (5.1) | **-** |
| Non-fuel electric revenues | **196.4** | 200.7 | **814.6** | 806.7 | 785.8 |
| **Electric margin** | **$ 196.4** | $ 195.9 | **$ 814.6** | $ 801.6 | $ 785.8 |

(1) NSPI removed "Fixed cost deferrals" from its calculation of electric margin in Q2 2014 as management believed it better reflected its business operations. Prior periods have been retroactively restated.

(2) As reported in "Other income (expenses) net", on the Consolidated Statement of Income.

NSPI's electric margin increased $0.5 million to $196.4 million in Q4 2015 compared to $195.9 million in Q4 2014 primarily due to a Q4 2014 FAM audit disallowance, partially offset by decreased residential and commercial load. NSPI's electric margin for the year ended December 31, 2015 increased $13.0 million to $814.6 million compared to $801.6 million in 2014 primarily due to increased residential load, largely due to weather and a FAM audit disallowance in 2014.

**Q4 Average Electric Margin (Dollars per MWh)**

| | | 2015 | 2014 | 2013 |
|---|---|---|---|---|
| Dollars per MWh | $ | **78** $ | 77 $ | 76 |

**Annual Average Electric Margin (Dollars per MWh)**

| | | 2015 | 2014 | 2013 |
|---|---|---|---|---|
| Dollars per MWh | $ | **78** $ | 78 $ | 75 |

NSPI's electric margin per MWh is consistent quarter-over-quarter and year-over-year.

## Regulatory Amortization

Regulatory amortization is included in "Depreciation and amortization" on the Consolidated Statements of Income. Highlights of the changes in regulatory amortization are summarized in the following table:

| For the<br>millions of Canadian dollars | | Three months ended<br>December 31 | | Year ended<br>December 31 |
|---|---|---|---|---|
| **Regulatory amortization – 2013** | **$** | | **$** | **37.4** |
| Decreased pre-2003 income tax regulatory asset amortization (1) | | | | (14.0) |
| 2012 Large Industrial Customers FCR amortization, which commenced in 2013, following the 2013 General Rate Application settlement agreement | | | | 2.4 |
| Other regulatory amortization | | | | (0.9) |
| **Regulatory amortization – 2014** | **$** | **8.9** | **$** | **24.9** |
| Decreased 2012 Large Industrial Customers Fixed Cost Recovery amortization, which commenced in 2013, following the 2013 General Rate Application settlement agreement | | (2.7) | | (2.7) |
| Other regulatory amortization | | (1.6) | | (1.4) |
| **Regulatory amortization – 2015** | **$** | **4.6** | **$** | **20.8** |

(1) The UARB's 2010 ROE decision has allowed NSPI flexibility in the recognition of additional amortization of the pre-2003 income tax regulatory asset in current periods, which accordingly reduces amortization in future periods resulting in a lower customer rate requirement.

## Provincial Grants and Taxes

NSPI pays annual grants to the Province of Nova Scotia in lieu of municipal taxation other than deed transfer tax.

## Income Taxes

NSPI is subject to corporate income tax at the statutory rate of 31.0 per cent (combined federal and provincial income tax rate) and Part VI.1 tax relating to preferred stock dividends at the statutory rate of 40.0 per cent. NSPI also receives a reduction in its corporate income tax otherwise payable related to the Part VI.1 tax deduction of 43.4 per cent of preferred stock dividends.

## Non-GAAP Measure

### Electric Margin Reconciliation

"Electric margin" is a non-GAAP financial measure used to show the amounts that NSPI retains to recover its non-fuel costs, as effectively all prudently incurred Fuel Costs are recovered through the FAM. NSPI's electric margin may not be comparable to other companies' electric margin measures, but in management's view appropriately reflects NSPI's regulatory framework. This measure is not intended to replace "Income from operations" which, as determined in accordance with GAAP, is an indicator of operating performance. Electric margin was discussed in the Financial Review Electric Margin section above.

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Income from operations | **$ 67.7** | $ 68.1 | **$ 289.8** | $ 274.0 | $ 295.0 |
| Less: | | | | | |
| Fuel electric revenues – current and preceding years | **137.1** | 124.2 | **574.5** | 512.5 | 518.5 |
| FAM audit disallowance | **-** | 4.8 | **-** | 5.1 | - |
| Other revenues | **5.0** | 7.8 | **28.2** | 29.0 | 30.6 |
| Add back: | | | | | |
| Regulated fuel for generation and purchased power | **132.4** | 127.4 | **542.8** | 511.7 | 556.9 |
| Operating, maintenance and general | **66.2** | 68.9 | **298.1** | 273.6 | 272.3 |
| Property, state and municipal taxes | **9.7** | 9.6 | **38.5** | 38.3 | 37.7 |
| Depreciation and amortization | **52.2** | 53.0 | **206.5** | 204.0 | 213.8 |
| Regulated fuel adjustment mechanism and fixed cost deferrals | **10.3** | 5.7 | **41.6** | 46.6 | (40.8) |
| Electric margin | $ **196.4** | **$** 195.9 | **$ 814.6** | $ 801.6 | $ 785.8 |

# EMERA MAINE

## Overview

Emera Maine is a transmission and distribution ("T&D") electric utility with assets of approximately $1.1 billion serving approximately 158,000 customers in the State of Maine in the United States. Effective January 1, 2014, Bangor Hydro Electric Company ("Bangor Hydro") and Maine Public Service Company ("MPS") merged, becoming Emera Maine.

Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the energy delivered through Emera Maine's T&D networks. Emera Maine owns and operates approximately 1,700 kilometres of transmission facilities and 15,000 kilometres of distribution facilities. Emera Maine's workforce is approximately 400 people.

Approximately 55 per cent of Emera Maine's electric revenue represents distribution operations, 31 per cent is associated with local transmission operations and 14 per cent relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

Distribution Operations

Emera Maine's distribution businesses operate under a traditional cost-of-service regulatory structure, and distribution rates are set by the MPUC. Prior to July 1, 2014, the allowed ROE was 10.2 per cent, on a common equity component of 50 per cent. On July 1, 2014, Emera Maine's distribution rates increased by nine per cent. Effective July 1, 2014, the allowed ROE became 9.55 per cent, on a common equity component of 49 per cent.

Transmission Operations

There are two transmission districts in Emera Maine, corresponding to the service territories of the two pre-merger entities.

*Bangor Hydro District*

Local transmission rates for Bangor Hydro District (the franchise electric service territory associated with the former Bangor Hydro Electric Company in portions of the Maine counties of Penobscot, Hancock, Washington, Waldo, Piscataquis, and Aroostook) are regulated by the FERC and set annually on June 1, based on a formula utilizing prior year actual transmission investments, adjusted for current year forecasted transmission investments. The allowed ROE up to October 15, 2014, for these local transmission investments, was 11.14 per cent. Effective October 16, 2014, the allowed ROE changed to 10.57 per cent, pending two outstanding complaints filed with the FERC to challenge the ISO-New England ("ISO-NE") Open Access Transmission Tariff-allowed base ROE of 11.14 per cent. The common equity component is based upon the prior calendar year actual average balances. Effective June 1, 2015, transmission rates for the Bangor Hydro District increased by approximately 21 per cent in connection with its annual transmission formula rate filing (2014 – increased by 13 per cent). The increase is associated primarily with the under-recovery of prior year regional transmission revenues collected in local rates, as well as the recovery of increased transmission plant in service.

The Bangor Hydro District's bulk transmission assets are managed by ISO-NE as part of a region-wide pool of assets. ISO-NE manages the region's bulk power generation and transmission systems and administers the open access transmission tariff. Currently, the Bangor Hydro District along with all other participating transmission providers, recovers the full cost of service for its transmission assets from the customers of participating transmission providers in New England, based on a regional FERC approved formula that is updated June 1 each year. This formula is based on prior year regionally funded transmission investments, adjusted for current year forecasted investments. Until October 15, 2014, Bangor Hydro District's allowed ROE for these transmission investments ranged from 11.64 per cent to 12.64 per cent. Effective October 16, 2014, the transmission investments allowed ROE changed to a range from 11.07 per cent to 11.74 per cent, pending the two aforementioned complaints filed with FERC. The common equity component is based upon the prior calendar year average balances. The participating transmission providers are also required to contribute to the cost of service of such transmission assets on a ratable basis according to the proportion of the total New England load that their customers represent.

On June 1, 2015, Bangor District's regionally recoverable transmission investments and expenses decreased by 6 per cent (2014 – increased by 7 per cent).

As at December 31, 2015, the Company had accrued $5.0 million associated with the FERC ROE complaints (2014 – $7.3 million). Refunds for the first FERC ROE complaint are being made to customers over a one-year period which began with the June 1, 2015 rate change.

*MPS District*

Local transmission rates for MPS District's (the franchise electric service territory associated with the former Maine Public Service Company in the Maine counties of Aroostook and a portion of Penobscot) are regulated by the FERC and are set annually on June 1 for wholesale and July 1 for retail customers, based on a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted investments. The current allowed ROE for transmission operations is 10.2 per cent. The common equity component is based upon the prior calendar year actual average balances. Effective June 1, 2015 the transmission rates for the MPS District decreased by approximately 24 per cent for wholesale customers (2014 – increased by 2 per cent) and on July 1, 2015 decreased by 22 per cent for retail customers (2014 – increased by 11 per cent) in connection with its annual transmission formula rate filing. These decreases were primarily due to an increase in wholesale transmission revenue that allows for a decrease in local customer transmission rates.

The MPS District electric service territory is not connected to the New England bulk power system and it is not a member of ISO-NE. MPS District is not a party to the previously discussed ROE complaints at the FERC.

Stranded Cost Recoveries

Stranded cost recoveries in Maine are set by the MPUC. Electric utilities are permitted to recover all prudently incurred stranded costs resulting from the restructuring of the industry in 2000 that could not be mitigated or that arose as a result of rate and accounting orders issued by the MPUC. Unlike transmission and distribution operational assets, which are generally sustained with new investment, the net stranded cost regulatory asset pool diminishes over time as elements are amortized through charges to income and recovered through rates. Generally, regulatory rates to recover stranded costs are set every three years, determined under a traditional cost-of-service approach and are fully recoverable. Each year on July 1, stranded cost rates are adjusted to reflect recovery of cost deferrals for the prior stranded costs rate year under the full recovery mechanism, as well as factor in any new stranded cost information.

*Bangor Hydro District*

Bangor Hydro District's net stranded regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract, and deferrals associated with reconciling stranded costs. These net regulatory assets total approximately $19.7 million as at December 31, 2015 (2014 – $25.1 million) or 1.8 per cent of Emera Maine's net asset base (2014 – 2.3 per cent).

On July 1, 2014, the Bangor Hydro District stranded cost rates decreased by 10 per cent. Earlier, on March 1, 2014, stranded costs rates had increased by 20 per cent. The allowed ROE used in setting the new rates on July 1, 2014, and March 1, 2014, was 5.9 per cent, with a common equity component of 48 per cent. This July 1, 2014 rate decrease remained in effect for all of 2015, and there was no rate change on July 1, 2015.

While the stranded cost revenue requirements differ throughout the period due to changes in annual stranded costs, the actual annual stranded cost revenues are the same during the period. To stabilize the impact of the varying revenue requirements, cost or revenue deferrals are recorded as a regulatory asset or liability, and addressed in subsequent stranded cost rate proceedings, where customer rates are adjusted accordingly.

*MPS District*

Effective January 1, 2015, the stranded cost rates for the MPS District decreased by approximately 150 per cent. This was principally due to the flow-back to customers of certain benefits received by Emera Maine from Maine Yankee associated with litigation with the United States Department of Energy on nuclear waste disposal. The allowed ROE used in setting the new rates on January 1, 2015 was 6.75 per cent, with a common equity component of 48 per cent. The reduced stranded cost revenues are offset by reductions in expense and do not affect income. This January 1, 2015, rate decrease remained in effect for all of 2015 and there was no rate change on July 1, 2015.

# Review of 2015

**Emera Maine Net Income**

| For the<br>millions of USD (except per share amounts) | Three months ended<br>December 31 | | For the year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Operating revenues – regulated | **$ 52.6** | $ 55.9 | **$ 221.6** | $ 219.0 | $ 211.2 |
| Operating revenues – non-regulated | **0.1** | - | **0.6** | 0.5 | 0.5 |
| **Total operating revenues** | **52.7** | 55.9 | **222.2** | 219.5 | 211.7 |
| Regulated fuel for generation and purchased power | **7.5** | 9.4 | **28.9** | 29.7 | 30.8 |
| Transmission pool expense (1) | **6.1** | 6.0 | **25.4** | 23.9 | 22.9 |
| Operating, maintenance and general | **14.2** | 10.3 | **49.1** | 47.0 | 44.2 |
| Provincial, state and municipal taxes | **2.8** | 3.2 | **12.8** | 11.5 | 10.2 |
| Depreciation and amortization | **9.5** | 9.5 | **36.5** | 43.3 | 35.9 |
| Total operating expenses | **40.1** | 38.4 | **152.7** | 155.4 | 144.0 |
| **Income from operations** | **12.6** | 17.5 | **69.5** | 64.1 | 67.7 |
| Other income (expenses), net | **(1.9)** | 0.9 | **0.8** | 4.2 | 3.3 |
| Interest expense, net | **3.4** | 3.5 | **13.7** | 12.2 | 12.2 |
| **Income before provision for income taxes** | **7.3** | 14.9 | **56.6** | 56.1 | 58.8 |
| Income tax expense (recovery) | **3.4** | 4.6 | **21.0** | 17.7 | 21.6 |
| **Contribution to consolidated net income – USD** | **$ 3.9** | $ 10.3 | **$ 35.6** | $ 38.4 | $ 37.2 |
| **Contribution to consolidated net income – CAD** | **$ 5.2** | $ 11.7 | **$ 45.1** | $ 42.4 | $ 38.4 |
| Contribution to consolidated earnings per common share – CAD | **$ 0.04** | $ 0.08 | **$ 0.31** | $ 0.30 | $ 0.29 |
| Net income weighted average foreign exchange rate – CAD/USD | **$ 1.33** | $ 1.14 | **$ 1.27** | $ 1.10 | $ 1.03 |
| | | | | | |
| EBITDA – USD | **$ 20.2** | $ 27.9 | **$ 106.8** | $ 111.6 | $ 106.9 |
| EBITDA – CAD | **$ 26.8** | $ 31.8 | **$ 136.0** | $ 123.4 | $ 110.3 |

(1) Transmission pool expense is included in “Regulated fuel for generation and purchased power” on the Consolidated Statements of Income.

Emera Maine’s USD contribution to consolidated net income decreased by $6.4 million to $3.9 million in Q4 2015 compared to $10.3 million in Q4 2014. For the year ended December 31, 2015, Emera Maine’s USD contribution to consolidated net income decreased by $2.8 million to $35.6 million compared to $38.4 million in 2014. Highlights of the USD net income changes are summarized in the following table:

| For the<br>millions of US dollars | | Three months ended<br>December 31 | | Year ended<br>December 31 |
|---|---|---|---|---|
| **Contribution to consolidated net income – 2013** | | | **$** | **37.2** |
| Increased operating revenues primarily due to rate changes | | | | 7.8 |
| Decreased regulated fuel for purchased power primarily due to changes in purchased power contracts | | | | 1.1 |
| Increased OM&G expenses primarily due to decreased capitalized construction overheads and increased storm expenses | | | | (2.8) |
| Increased depreciation and amortization primarily due to increased plant in service | | | | (7.4) |
| Decreased income tax expense primarily due to decreased income before provision for income taxes, a change in estimate of prior year expected benefit of tax deductions and changes in regulatory amortization | | | | 3.9 |
| Other | | | | (1.4) |
| **Contribution to consolidated net income – 2014** | **$** | **10.3** | **$** | **38.4** |
| (Decreased) increased operating revenues – see Operating Revenues – Regulated section below | | (3.3) | | 2.6 |
| Increased OM&G primarily due to decreased capitalized construction overheads, partially offset by changes in pension and retiree medical expenses | | (3.9) | | (2.1) |
| Decreased depreciation and amortization due to lower depreciation rates as a result of a 2014 depreciation study and lower regulatory amortization; no change quarter-over-quarter as lower depreciation rates are offset by increased regulatory amortization | | - | | 6.8 |
| Decreased other income primarily due to AFUDC adjustments recognized as a result of a FERC audit | | (2.8) | | (3.4) |
| Decreased income tax expense quarter-over-quarter primarily due to lower income before provision for income taxes, partially offset by AFUDC adjustments recorded as a result of a FERC audit; year-over-year increase primarily due to decrease in regulatory amortization and AFUDC adjustments recorded as a result of a FERC audit | | 1.2 | | (3.3) |
| Other | | 2.4 | | (3.4) |
| **Contribution to consolidated net income – 2015** | **$** | **3.9** | **$** | **35.6** |

Emera Maine's CAD contribution to consolidated net income decreased by $6.5 million to $5.2 million in Q4 2015 from $11.7 million in Q4 2014. For the year ended December 31, 2015, Emera Maine's CAD contribution to consolidated net income increased by $2.7 million to $45.1 million from $42.4 million in 2014. The impact of a stronger USD, increased CAD earnings quarter-over-quarter by $0.7 million for the three months ended December 31, 2015 and year-over-year $6.1 million for the year ended December 31, 2015.

## Operating Revenues – Regulated

Emera Maine's operating revenues – regulated include sales of electricity and other services as summarized in the following table:

**Q4 Operating Revenues – Regulated**
millions of US dollars

| | | **2015** | | 2014 | | 2013 |
|---|---|---|---|---|---|---|
| Electric revenues | **$** | **38.0** | $ | 41.2 | $ | 39.3 |
| Transmission pool revenues | | **11.0** | | 11.3 | | 11.3 |
| Resale of purchased power | | **3.6** | | 3.4 | | 3.5 |
| Operating revenues – regulated | **$** | **52.6** | $ | 55.9 | $ | 54.1 |

**Annual Operating Revenues – Regulated**
millions of US dollars

| | | **2015** | | 2014 | | 2013 |
|---|---|---|---|---|---|---|
| Electric revenues | **$** | **160.0** | $ | 156.8 | $ | 146.9 |
| Transmission pool revenues | | **49.1** | | 49.0 | | 50.7 |
| Resale of purchased power | | **12.5** | | 13.2 | | 13.6 |
| Operating revenues – regulated | **$** | **221.6** | $ | 219.0 | $ | 211.2 |

## Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather. Electric sales pricing in Maine is regulated, and therefore can change in accordance with regulatory decisions.

**Q4 Electric Sales Volumes**

| GWh | **2015** | 2014 | 2013 |
|---|---|---|---|
| Residential | **199** | 203 | 209 |
| Commercial | **192** | 193 | 198 |
| Industrial | **94** | 104 | 107 |
| Other | **3** | 4 | 4 |
| Total | **488** | 504 | 518 |

**Annual Electric Sales Volumes**

| GWh | **2015** | 2014 | 2013 |
|---|---|---|---|
| Residential | **802** | 805 | 801 |
| Commercial | **781** | 788 | 798 |
| Industrial | **423** | 426 | 424 |
| Other | **14** | 15 | 15 |
| Total | **2,020** | 2,034 | 2,038 |

Electric revenues are summarized in the following tables by customer class:

**Q4 Electric Revenues**
millions of US dollars

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Residential | **$ 19.2** | $ 19.8 | $ 18.9 |
| Commercial | **14.8** | 14.7 | 14.2 |
| Industrial | **3.2** | 3.8 | 3.6 |
| Other (1) | **0.8** | 2.9 | 2.6 |
| Total | **$ 38.0** | $ 41.2 | $ 39.3 |

**Annual Electric Revenues**
millions of US dollars

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Residential | **$ 76.4** | $ 75.8 | $ 71.7 |
| Commercial | **57.9** | 57.2 | 54.7 |
| Industrial | **14.1** | 14.2 | 13.1 |
| Other (1) | **11.6** | 9.6 | 7.4 |
| Total | **$ 160.0** | $ 156.8 | $ 146.9 |

(1) Other revenue includes amounts recognized relating to FERC transmission rate refunds and other transmission revenue adjustments.

Electric revenues decreased $3.2 million to $38.0 million in Q4 2015 compared to $41.2 million in Q4 2014. For the year ended December 31, 2015, electric revenues increased $3.2 million to $160.0 million in 2015 compared to $156.8 million in 2014. Highlights of the changes are summarized in the following table:

| For the<br>millions of US dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Electric revenues – 2013** | | **$ 146.9** |
| Decreased sales volumes primarily due to weather | | (0.2) |
| Increased primarily due to rate changes | | 9.5 |
| Decreased due to changes in amounts recognized related to the FERC ROE complaints | | (2.6) |
| Change in estimate for the transmission revenue | | 3.2 |
| **Electric revenues – 2014** | **$ 41.2** | **$ 156.8** |
| Decreased sales volumes primarily due to weather | (1.2) | (1.1) |
| Increased primarily due to rate changes | 0.5 | 3.8 |
| Increased due to FERC transmission rate refund | 3.9 | 6.0 |
| Decreased due to transmission revenue adjustments | (6.4) | (5.5) |
| **Electric revenues – 2015** | **$ 38.0** | **$ 160.0** |

**Q4 Electric Revenue / MWh**

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Dollars per MWh | **$ 78** | $ 82 | $ 76 |

**Annual Average Electric Revenue / MWh**

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Dollars per MWh | **$ 79** | $ 77 | $ 72 |

The change in average electric revenue per MWh in Q4 2015 compared to Q4 2014 and for the year ended December 31, 2015 compared to the same period in 2014 reflects transmission revenue adjustments and changes in the amounts recorded related to the transmission rate refund associated with the FERC ROE complaints.

## Transmission Pool Revenues and Expenses

Transmission pool expenses are recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income. Transmission pool revenues are recorded in "Operating revenues – regulated" in the Consolidated Statements of Income.

Transmission pool revenues and expenses are summarized in the following table:

| For the<br>millions of US dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Transmission pool revenues | **$ 11.0** | $ 11.3 | **$ 49.1** | $ 49.0 | $ 50.7 |
| Transmission pool expenses | **6.1** | 6.0 | **25.4** | 23.9 | 22.9 |
| Net transmission pool revenues | **$ 4.9** | $ 5.3 | **$ 23.7** | $ 25.1 | $ 27.8 |

Emera Maine's net transmission pool revenues decreased $0.4 million to $4.9 million in Q4 2015 compared to $5.3 million in Q4 2014. For the year ended December 31, 2015, net transmission pool revenues decreased $1.4 million to $23.7 million compared to $25.1 million in 2014 primarily due to changes in the level of investment in regionally funded transmission assets and the impacts of weather in the New England region.

## Resale of Purchased Power and Regulated Fuel for Generation and Purchased Power

Emera Maine has several above-market power purchase contracts with generators in its Bangor District service territory. The power purchased under these arrangements is resold at market rates significantly below the contract rates. The difference between the cost of the power purchased under these arrangements and the revenue collected is recovered through stranded cost rates under a full reconciliation rate mechanism.

Resale of purchased power increased $0.2 million in Q4 2015 to $3.6 million compared to $3.4 million in Q4 2014, and for the year ended December 31, 2015 decreased $0.7 million to $12.5 million in 2015 compared to $13.2 million in 2014 primarily due to changes in market rates for electricity in New England in 2015.

## Income Taxes

Emera Maine is subject to corporate income tax at the statutory rate of 40.8 per cent (combined US federal and state income tax rate).

# EMERA CARIBBEAN

## Overview

Emera Caribbean includes the following consolidated and non-consolidated investments:

**Consolidated Investments**

- 95.5 per cent (2014 – 80.6 per cent) investment in Emera (Caribbean) Incorporated (“ECI”) and its wholly owned subsidiary Barbados Light & Power Company Ltd. (“BLPC”), a vertically integrated utility and the provider of electricity on the island of Barbados, serving approximately 126,000 customers and regulated by the Fair Trading Commission, Barbados. The government of Barbados has granted BLPC a franchise to generate, transmit and distribute electricity on the island until 2028. BLPC owns 239 MW of oil-fired generation, 116 kilometres of transmission facilities and 2,800 kilometres of distribution facilities. BLPC has a workforce of 330 people. BLPC is regulated under a cost-of-service model with rates set to recover prudently incurred costs of providing electricity service to customers, and to provide an appropriate return to investors. BLPC’s approved allowed regulated return on rate base for 2015 was 10.0 per cent. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner. Emera has initiated a process to purchase the remaining 4.5 per cent of common shares from minority shareholders of ECI, with anticipated completion in Q1 2016.

- 50.0 per cent direct and 30.4 per cent indirect interest (through a 60.7 per cent interest in ICD Utilities Limited (“ICDU”) in Grand Bahama Power Company Ltd. (“GBPC”), which is a vertically integrated utility and the sole provider of electricity on Grand Bahama Island. GBPC serves approximately 19,000 customers. GBPC owns 98 MW of oil-fired generation, 138 kilometres of transmission facilities and 850 kilometres of distribution facilities and has a workforce of 205 people. GBPC is regulated by GBPA, which has granted GBPC a licensed, regulated and exclusive franchise to generate, transmit and distribute electricity on the island until 2054. GBPC’s approved allowable regulated return on rate base for 2015 was 10.0 per cent. A fuel pass-through mechanism provides the opportunity to recover all fuel costs in a timely manner. Effective February 1, 2016, the GBPA approved GBPC’s General Rate Application applicable for the 2016 through 2018 period. Residential customers will see decreases up to 4.5 per cent, while commercial customers will see an increase of 1.5 per cent. Commercial customers consume approximately 70 per cent of GBPC’s production. Rates were approved based upon an 8.8 per cent allowable return on rate base. This rate decision will allow for customers to install renewable energy systems and sell their excess energy to GBPC. This is based on a tariff rider scheduled to be in place by Q3 2016.

- 49.6 per cent (2014 – 41.8 per cent) indirect controlling interest, through ECI, in Dominica Electricity Services Ltd. (“Domlec”), an integrated utility on the island of Dominica. Domlec serves approximately 36,000 customers and is regulated by the Independent Regulatory Commission, Dominica. Domlec owns 20 MW of oil-fired generation, 7 MW of hydro production, 452 kilometres of transmission facilities and 640 kilometres of distribution facilities. Domlec has a workforce of 238 people. On October 7, 2013, the Independent Regulatory Commission, Dominica issued a Transmission, Distribution & Supply License and a Generation License, both of which came into effect on January 1, 2014, for a period of 25 years. Domlec’s approved allowable regulated return on rate base for 2015 was 15 per cent. A fuel pass-through mechanism provides the opportunity to recover substantially all fuel costs in a timely manner.

- EUS Bahamas, providing utility construction and plant operation services in The Bahamas.

**Equity Investment**

- 18.2 per cent indirect interest (2014 – 15.4 per cent), through ECI, in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia, which is regulated by the Government of St. Lucia. The investment in Lucelec is accounted for on the equity basis.

# Review of 2015

**Emera Caribbean Net Income**

| For the<br>millions of USD (except per share amounts) | | Three months ended<br>December 31 | | | Year ended<br>December 31 | |
|---|---|---|---|---|---|---|
| | | **2015** | 2014 | **2015** | 2014 | 2013 |
| Operating revenues – regulated | **$** | **84.3** | $ 105.4 | **$ 346.0** | $ 432.1 | $ 427.4 |
| Operating revenues – non-regulated | | **-** | 2.2 | **6.0** | 8.0 | 8.7 |
| **Total operating revenues** | | **84.3** | 107.6 | **352.0** | 440.1 | 436.1 |
| Regulated fuel for generation and purchased power | | **37.0** | 60.0 | **158.1** | 247.6 | 248.6 |
| Non-regulated direct costs | | **0.2** | 1.8 | **5.9** | 7.1 | 7.6 |
| Operating, maintenance and general | | **23.7** | 28.6 | **101.5** | 107.3 | 103.7 |
| Property taxes (1) | | **0.2** | 0.4 | **1.8** | 1.6 | 1.5 |
| Depreciation and amortization | | **8.6** | 7.7 | **34.5** | 33.3 | 30.9 |
| Total operating expenses | | **69.7** | 98.5 | **301.8** | 396.9 | 392.3 |
| **Income from operations** | | **14.6** | 9.1 | **50.2** | 43.2 | 43.8 |
| Income from equity investment | | **0.6** | 0.4 | **2.3** | 2.1 | 1.7 |
| Other income (expenses), net | | **1.9** | 1.3 | **4.8** | 5.7 | 11.8 |
| Interest expense, net | | **2.7** | 2.7 | **10.8** | 11.5 | 11.7 |
| **Income before provision for income taxes** | | **14.4** | 8.1 | **46.5** | 39.5 | 45.6 |
| Income tax expense (recovery) | | **1.5** | 0.9 | **2.4** | 2.7 | 3.2 |
| Net income | | **12.9** | 7.2 | **44.1** | 36.8 | 42.4 |
| Non-controlling interest in subsidiaries | | **2.9** | 1.9 | **10.2** | 8.3 | 8.9 |
| Preferred stock dividends (2) | | **-** | - | **2.5** | 2.5 | 1.2 |
| **Contribution to consolidated net income – USD** | **$** | **10.0** | $ 5.3 | **$ 31.4** | $ 26.0 | $ 32.3 |
| **Contribution to consolidated net income – CAD** | **$** | **13.3** | $ 6.1 | **$ 40.5** | $ 28.7 | $ 33.4 |
| Contribution to consolidated earnings per common share – CAD | **$** | **0.09** | $ 0.04 | **$ 0.28** | $ 0.20 | $ 0.25 |
| Net income weighted average foreign exchange rate – CAD/USD | **$** | **1.33** | $ 1.15 | **$ 1.29** | $ 1.10 | $ 1.03 |
| | | | | | | |
| EBITDA – USD | **$** | **25.7** | $ 18.5 | **$ 91.8** | $ 84.3 | $ 88.2 |
| EBITDA – CAD | **$** | **34.3** | $ 21.0 | **$ 117.9** | $ 93.0 | $ 91.1 |

(1) Included in "Provincial, state and municipal taxes" on the Consolidated Statements of Income.

(2) Preferred stock dividends are included in "Non-controlling interest in subsidiaries" on the Consolidated Statements of Income.

Emera Caribbean's USD contribution to consolidated net income increased by $4.7 million to $10.0 million in Q4 2015 compared to $5.3 million in Q4 2014. For the year ended December 31, 2015, Emera Caribbean's USD contribution to consolidated net income increased by $5.4 million to $31.4 million compared to $26.0 million in 2014. Highlights of the net income changes are summarized in the following table:

| For the<br>millions of US dollars | | Three months ended<br>December 31 | | Year ended<br>December 31 |
|---|---|---|---|---|
| **Contribution to consolidated net income – 2013** | | | **$** | **32.3** |
| Increased OM&G expenses due to restructuring costs at ECI, partially offset by operational cost savings at GBPC | | | | (0.4) |
| Decreased other income (expenses), net primarily due to reduced investment income relating to an adjustment to ECI's self-insurance fund | | | | (3.4) |
| Increased preferred dividends due to timing of preferred share issuance | | | | (1.3) |
| Effect of the non-taxable gain on acquisition of Domlec, partially offset by the acquisition of controlling interest in Domlec on April 10, 2013 | | | | (2.0) |
| Other | | | | 0.8 |
| **Contribution to consolidated net income – 2014** | **$** | **5.3** | **$** | **26.0** |
| Increased Electric Margin – see Electric Margin section | | 1.8 | | 3.7 |
| Decreased OM&G primarily due to lower pension expense, savings and timing of maintenance costs, and restructuring payroll savings at BLPC, lower outage costs at GBPC, and the reversal of Domlec regulatory costs; year-over-year restructuring costs at BLPC offset the decreased OM&G | | 4.9 | | 5.8 |
| Increased non-controlling interest due to increased earnings from ECI, GBPC and Domlec | | (1.0) | | (1.9) |
| Other | | (1.0) | | (2.2) |
| **Contribution to consolidated net income – 2015** | **$** | **10.0** | **$** | **31.4** |

Emera Caribbean's CAD contribution to consolidated net income increased by $7.2 million to $13.3 million in Q4 2015 compared to $6.1 million in Q4 2014. For the year ended December 31, 2015, Emera Caribbean's CAD contribution to consolidated net income increased by $11.8 million to $40.5 million in 2015 compared to $28.7 million in 2014. The impact of a stronger USD, quarter-over-quarter increased CAD earnings by $1.8 million for the three months ended December 31, 2015 compared to 2014. The impact of a stronger USD year-over-year increased CAD earnings by $6.0 million in 2015 compared to 2014.

## Operating Revenues – Regulated

Emera Caribbean's operating revenues – regulated include sales of electricity and other services as summarized in the following table:

**Q4 Operating Revenues – Regulated**

millions of US dollars

| | | 2015 | 2014 | | 2013 |
|---|---|---|---|---|---|
| Electric revenues – base rates | **$** | **47.1** | 45.2 | $ | 45.4 |
| Fuel charge | | **36.3** | 59.4 | | 60.3 |
| Total electric revenues | | **83.4** | 104.6 | | 105.7 |
| Other revenues | | **0.9** | 0.8 | | 0.8 |
| Operating revenues – regulated | **$** | **84.3** | 105.4 | $ | 106.5 |

**Annual Operating Revenues – Regulated**

millions of US dollars

| | | 2015 | | 2014 | | 2013* |
|---|---|---|---|---|---|---|
| Electric revenues – base rates | **$** | **186.7** | $ | 182.7 | $ | 177.0 |
| Fuel charge | | **155.4** | | 245.2 | | 247.0 |
| Total electric revenues | | **342.1** | | 427.9 | | 424.0 |
| Other revenues | | **3.9** | | 4.2 | | 3.4 |
| Operating revenues – regulated | **$** | **346.0** | $ | 432.1 | $ | 427.4 |

*ECI acquired a 51.9 per cent controlling interest in Domlec on April 10, 2013.

## Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q3 being the strongest period, reflecting warmer weather.

**Q4 Electric Sales Volumes**
GWh

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Residential | **115** | 111 | 110 |
| Commercial | **197** | 189 | 191 |
| Industrial | **25** | 26 | 18 |
| Other | **7** | 7 | 7 |
| Total | **344** | 333 | 326 |

**Annual Electric Sales Volumes**
GWh

| | **2015** | 2014 | 2013* |
|---|---|---|---|
| Residential | **453** | 440 | 428 |
| Commercial | **764** | 751 | 744 |
| Industrial | **104** | 102 | 93 |
| Other | **24** | 26 | 26 |
| Total | **1,345** | 1,319 | 1,291 |

* ECI acquired a 51.9 per cent controlling interest in Domlec on April 10, 2013.

Electric volumes increased in Q4 2015 compared to Q4 2014 and for the year ended December 31, 2015 as a result of warmer weather.

Electric revenues are summarized in the following tables by customer class:

**Q4 Electric Revenues**
millions of US dollars

| | | **2015** | | 2014 | | 2013 |
|---|---|---|---|---|---|---|
| Residential | **$** | **26.9** | $ | 34.5 | $ | 33.3 |
| Commercial | | **47.7** | | 60.7 | | 62.9 |
| Industrial | | **7.2** | | 7.5 | | 7.6 |
| Other | | **1.6** | | 1.9 | | 1.9 |
| Total | **$** | **83.4** | $ | 104.6 | $ | 105.7 |

**Annual Electric Revenues**
millions of US dollars

| | | **2015** | | 2014 | | 2013* |
|---|---|---|---|---|---|---|
| Residential | $ | **110.9** | $ | 142.9 | $ | 133.2 |
| Commercial | | **194.8** | | 250.7 | | 251.5 |
| Industrial | | **30.1** | | 26.9 | | 31.5 |
| Other | | **6.3** | | 7.4 | | 7.8 |
| Total | $ | **342.1** | $ | 427.9 | $ | 424.0 |

* ECI acquired a 51.9 per cent controlling interest in Domlec on April 10, 2013.

Electric revenues decreased $21.2 million to $83.4 million in Q4 2015 compared to $104.6 million in Q4 2014. For the year ended December 31, 2015, electric revenues decreased $85.8 million to $342.1 million compared to $427.9 million in 2014. Highlights of the changes are summarized in the following table:

| For the<br>millions of US dollars | | Three months ended<br>December 31 | | Year ended<br>December 31 |
|---|---|---|---|---|
| **Electric revenues – 2013** | | | **$** | **424.0** |
| Increased due to acquisition of a controlling interest in Domlec | | | | 8.2 |
| Decreased fuel charge primarily due to lower fuel prices | | | | (4.8) |
| Increased due to higher sales volumes in GBPC | | | | 0.5 |
| **Electric revenues – 2014** | **$** | **104.6** | **$** | **427.9** |
| Decreased fuel charge primarily due to lower fuel prices | | (23.1) | | (89.8) |
| Increased due to higher sales volumes at BLPC and GBPC primarily due to weather | | 1.9 | | 4.0 |
| **Electric revenues – 2015** | **$** | **83.4** | **$** | **342.1** |

**Q4 Average Electric Revenue/MWh**

| | | 2015 | 2014 | 2013 |
|---|---|---|---|---|
| Dollars per MWh | $ | **242** | $ 314 | $ 324 |

**Annual Average Electric Revenue/MWh**

| | | 2015 | 2014 | 2013* |
|---|---|---|---|---|
| Dollars per MWh | $ | **254** | $ 324 | $ 328 |

*ECI acquired a 51.9 per cent controlling interest in Domlec on April 10, 2013.

The change in average electric revenues in Q4 2015 compared to Q4 2014, and for the year ended December 31, 2015 compared to the same period in 2014, is a result of the decreased fuel charge primarily due to lower fuel prices.

## Electric Margin

Emera Caribbean distinguishes revenues related to the recovery of fuel costs through the fuel charge from revenues related primarily to the recovery of non-fuel costs ("base rates"). Emera Caribbean's electric margin and net income are influenced primarily by base rates, whereas the fuel charge and fuel costs do not have a material effect on electric margin or net income. Emera Caribbean's customer classes contribute differently to the Company's base rate revenue, with residential and commercial customers contributing more than industrial customers. Residential and commercial load is primarily affected by changes in weather and economic conditions, while industrial load is primarily affected by economic conditions.

Electric margin is summarized in the following table:

| For the<br>millions of US dollars | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013(1) |
| Operating revenues – regulated | **$ 84.3** | $ 105.4 | **$ 346.0** | $ 432.1 | $ 427.4 |
| Less: Other revenues | **(0.9)** | (0.8) | **(3.9)** | (4.2) | (3.4) |
| Total electric revenues | **83.4** | 104.6 | **342.1** | 427.9 | 424.0 |
| *Total electric revenues are broken down as follows:* | | | | | |
| Electric revenues – base rate | **$ 47.1** | $ 45.2 | **$ 186.7** | $ 182.7 | $ 177.0 |
| Fuel charge | **36.3** | 59.4 | **155.4** | 245.2 | 247.0 |
| **Total electric revenues** | **83.4** | 104.6 | **342.1** | 427.9 | 424.0 |
| Regulated fuel for generation and purchased power | **37.0** | 60.0 | **158.1** | 247.6 | 248.6 |
| Regulatory amortization (2) | **0.7** | 0.7 | **2.9** | 2.9 | 2.9 |
| **Electric margin** | **$ 45.7** | $ 43.9 | **$ 181.1** | $ 177.4 | $ 172.5 |

(1) ECI acquired a 51.9 per cent controlling interest in Domlec on April 10, 2013.
(2) Included in "Depreciation and amortization" on the Consolidated Statements of Income.

Emera Caribbean's electric margin increased $1.8 million to $45.7 million in Q4 2015 compared to $43.9 million in Q4 2014. For the year ended December 31, 2015, electric margin increased $3.7 million to $181.1 million compared to $177.4 million in 2014 primarily due to increased sales volume at BLPC and GBPC primarily due to weather.

**Q4 Average Electric Margin / MWh**

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| Dollars per MWh | **$ 133** | $ 132 | $ 135 |

**Annual Average Electric Margin / MWh**

| | 2015 | 2014 | 2013* |
|---|---|---|---|
| Dollars per MWh | **$ 135** | $ 134 | $ 134 |

*ECI acquired a 51.9 per cent controlling interest of Domlec on April 10, 2013.

## Regulated Fuel for Generation and Purchased Power

**Q4 Production Volumes**
GWh

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Oil | **369** | 349 | 345 |
| Hydro | **6** | 8 | 10 |
| Total | **375** | 357 | 355 |

**Annual Production Volumes**
GWh

| | **2015** | 2014 | 2013* |
|---|---|---|---|
| Oil | **1,441** | 1,397 | 1,371 |
| Hydro | **25** | 31 | 30 |
| Total | **1,466** | 1,428 | 1,401 |

*ECI acquired a 51.9 per cent controlling interest in Domlec on April 10, 2013

**Q4 Average Fuel Costs/MWh**

| | **2015** | 2014 | 2013 |
|---|---|---|---|
| Dollars per MWh | **$ 99** | $ 168 | $ 172 |

**Annual Average Fuel Costs/MWh**

| | **2015** | 2014 | 2013* |
|---|---|---|---|
| Dollars per MWh | **$ 108** | $ 173 | $ 177 |

*ECI acquired a 51.9 per cent controlling interest in Domlec on April 10, 2013

The change in average fuel costs in Q4 2015 compared to Q4 2014 and for the year ended December 31, 2015 compared to the same period in 2014 is a result of lower fuel prices.

Regulated fuel for generation and purchased power decreased $23.0 million to $37.0 million in Q4 2015 compared to $60.0 million in Q4 2014. For the year ended December 31, 2015, regulated fuel for generation and purchased power decreased $89.5 million to $158.1 million compared to $247.6 million in 2014 primarily due to lower fuel prices.

## Regulatory Recovery Mechanisms

### BLPC

All BLPC fuel costs are passed to customers through the fuel pass-through mechanism which provides the opportunity to recover all fuel costs in a timely manner. The Fair Trading Commission, Barbados has approved the calculation of the fuel charge, which is adjusted on a monthly basis.

### GBPC

All GBPC fuel costs are passed to customers through the fuel pass-through mechanism which provides the opportunity to recover all fuel costs in a timely manner. The GBPA has approved the calculation of the fuel charge, which is adjusted on a monthly basis.

As a component of its regulatory agreement with the GBPA, GBPC has an Earnings Share Mechanism to allow for earnings on rate base to be deferred to a regulatory asset or liability at the rate of 50 per cent of amounts below a nine-per- cent return on rate base and 50 per cent of amounts above 11 per cent return on rate base respectively.

### Domlec

Substantially all of Domlec fuel costs are passed to customers through the fuel pass-through mechanism which provides the opportunity to recover fuel costs in a timely manner.

## Income Taxes

Emera Caribbean is subject to corporate income tax at the following statutory rates:

- ECI is subject to corporate income tax at the statutory rate of 25.0 per cent;
- BLPC is subject to corporate income tax at the statutory rate of 15.0 per cent;
- GBPC is not subject to corporate income tax;
- Domlec is subject to corporate income tax at the statutory rate of 28.0 per cent; and
- Lucelec is subject to corporate income tax at the statutory rate of 30.0 per cent.

## Non-GAAP Measure

### Electric Margin Reconciliation

"Electric margin" is a non-GAAP financial measure used to show the amounts that BLPC, GBPC and Domlec retain to recover their non-fuel costs, as substantially all prudently incurred fuel costs are recovered from customers.

The companies' electric margin may not be comparable to electric margin measures of other companies, but in management's view appropriately reflects Emera's specific condition. This measure is not intended to replace "Income from operations" which, as determined in accordance with GAAP, is an indicator of operating performance.

| For the<br>millions of US dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Income from operations | **$ 14.6** | $ 9.1 | **$ 50.2** | $ 43.2 | $ 43.8 |
| less: | | | | | |
| Operating revenues – non-regulated | **-** | 2.2 | **6.0** | 8.0 | 8.7 |
| Other revenue | **0.9** | 0.8 | **3.9** | 4.2 | 3.4 |
| Add back: | | | | | |
| Non-regulated direct costs | **0.2** | 1.8 | **5.9** | 7.1 | 7.6 |
| Operating, maintenance and general | **23.7** | 28.6 | **101.5** | 107.3 | 103.7 |
| Property taxes | **0.2** | 0.4 | **1.8** | 1.6 | 1.5 |
| Depreciation and amortization (1) | **7.9** | 7.0 | **31.6** | 30.4 | 28.0 |
| Electric margin | $ **45.7** | $ 43.9 | **$ 181.1** | $ 177.4 | **$** 172.5 |

(1) Depreciation and amortization excludes $0.7 million of regulatory amortization in Q4 2015 (2014 – $0.7 million) and $2.9 million for the year ended December 31, 2015 (2014 – $2.9 million)

# PIPELINES

## Overview

Pipelines comprises Emera's wholly owned Brunswick Pipeline and the Company's 12.9 per cent interest in the M&NP.

- Brunswick Pipeline is a 145-kilometre pipeline delivering re-gasified natural gas from the Canaport™ liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick, to markets in the northeastern United States for Repsol Energy Canada under a 25-year firm service agreement which expires in 2034. The NEB, which regulates Brunswick Pipeline, has classified it as a Group II pipeline. The agreement is accounted for as a direct financing lease.

- M&NP is a 1,400-kilometre transmission pipeline built to transport natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States. The investment in M&NP is accounted for on the equity basis.

**Mark-to-Market Adjustments**

Pipelines' "Interest expense, net" and "Income tax expense (recovery)" are affected by mark-to-market adjustments on an interest rate swap. Pipelines' income table below shows these amounts net of mark-to-market adjustments and details the adjustments in the footnotes.

## Review of 2015

**Pipelines' Adjusted Net Income**

| For the<br>millions of Canadian dollars (except per share amounts) | | Three months ended<br>December 31 | | | Year ended<br>December 31 | |
|---|---|---|---|---|---|---|
| | | **2015** | 2014 | **2015** | 2014 | 2013 |
| Operating revenues – regulated | **$** | **13.0** $ | 12.4 **$** | **52.1** $ | 48.8 $ | 49.9 |
| Operating maintenance and general | | **0.1** | 0.1 | **0.4** | 0.4 | 0.1 |
| Accretion (1) | | **0.1** | 0.1 | **0.4** | 0.3 | 0.2 |
| Income from equity investment | | **6.5** | 5.3 | **23.0** | 18.4 | 14.7 |
| Other income (expenses), net | | **-** | 0.2 | **0.6** | 0.6 | 0.1 |
| Interest expense, net (2) | | **6.0** | 6.8 | **23.3** | 26.0 | 27.6 |
| **Adjusted income before provision for income taxes** | | **13.3** | 10.9 | **51.6** | 41.1 | 36.8 |
| Income tax expense (recovery) (3) | | **3.2** | 2.4 | **12.0** | 8.4 | 6.5 |
| **Adjusted contribution to consolidated net income** | **$** | **10.1** $ | 8.5 **$** | **39.6** $ | 32.7 $ | 30.3 |
| After-tax derivative mark-to-market gain (loss) | | **0.2** | - | **(2.1)** | - | - |
| **Contribution to consolidated net income** | **$** | **10.3** $ | 8.5 **$** | **37.5** $ | 32.7 $ | 30.3 |
| Adjusted contribution to consolidated earnings per common share | **$** | **0.07** $ | 0.06 **$** | **0.27** $ | 0.23 $ | 0.23 |
| Contribution to consolidated earnings per common share | **$** | **0.07** $ | 0.06 **$** | **0.26** $ | 0.23 $ | 0.23 |
| | | | | | | |
| Adjusted EBITDA | **$** | **19.4** $ | 17.8 **$** | **75.3** $ | 67.4 $ | 64.6 |

(1) Accretion related to the reclamation of the pipeline is included in "Depreciation and amortization" on the Consolidated Statements of Income.
(2) Interest expense, net excludes a pre-tax mark-to-market gain of $0.2 million in Q4 2015 and $2.9 million loss for the year ended December 31, 2015 compared to nil for the same periods in 2014.
(3) Income tax expense (recovery) excludes a nil expense relating to mark-to-market gains in Q4 2015 and $0.8 million recovery relating to mark-to-market losses for the year ended December 31, 2015 compared to nil for the same periods in 2014.

Pipelines' contribution to consolidated net income increased by $1.8 million to $10.3 million in Q4 2015 compared to $8.5 million in Q4 2014 and increased $4.8 million to $37.5 million for the year ended December 31, 2015 compared to $32.7 million in 2014. Highlights of the income changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2013** | | **$ 30.3** |
| Increased income from equity investments primarily due to higher equity earnings from M&NP | | 3.7 |
| Other | | (1.3) |
| **Contribution to consolidated net income – 2014** | **$ 8.5** | **$ 32.7** |
| Increased regulated operating revenues due to a strengthening USD and increased tolls | 0.6 | 3.3 |
| Increased income from equity investments primarily due to increased interruptible transmission revenue from M&NP and the strengthening USD | 1.2 | 4.6 |
| Decreased interest expense, net primarily due to a lower interest rate on Brunswick Pipeline refinancing in Q1 2015 | 0.8 | 2.7 |
| Increased income tax expense primarily due to increased income before provision for income taxes | (0.8) | (3.6) |
| After-tax mark-to-market gain (loss) on an interest rate swap entered into in Q2 2015 | 0.2 | (2.1) |
| Other | (0.2) | (0.1) |
| **Contribution to consolidated net income – 2015** | **$ 10.3** | **$ 37.5** |

## Brunswick Pipeline

The Company records the net investment in a lease under the direct finance method, which consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income.  This accounting method has the effect of recognizing higher revenues in the early years of the contract than would have been recorded if the toll revenues were recorded as received.

## Income Taxes

Brunswick Pipeline is subject to corporate income tax at the statutory rate of 27.0 per cent (combined Canadian federal and provincial income tax rate).

# EMERA ENERGY

## Overview

Emera Energy includes the following:

- Emera Energy Services ("EES"), a wholly owned physical energy marketing and trading business;
- Emera Energy Generation ("EEG"), consisting of a wholly owned portfolio of electricity generation facilities in New England and the Maritime provinces of Canada with 1,410 megawatts ("MW") of total capacity;
- Equity investments in the following generation facilities:
  - Emera's 50.0 per cent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts.
  - Emera's 49.0 per cent investment in NWP, a 419 MW portfolio of wind energy projects in the northeastern United States which on January 29, 2015 sold to 51 per cent partner, First Wind.

Wholly owned investments are consolidated. The investment in Bear Swamp is accounted for on an equity basis. NWP was accounted for on the equity basis, and its results were included until its sale on January 29, 2015. The gain on the sale of this asset is recorded in "Other income (expenses), net" on the Consolidated Statements of Income.

**Mark-to-Market Adjustments**

Emera Energy's "Trading and marketing margin", "Electricity sales", "Non-regulated fuel for generation and purchased power", "Income from equity investments" and "Income tax expense (recovery)" are affected by mark-to-market ("MTM") adjustments. The Emera Energy income table shows these amounts net of mark-to-market adjustments and details these adjustments in footnotes to the income statement. Management believes that excluding the effect of mark-to-market valuations, and changes thereto, from income until settlement better matches the financial effect of these contracts with the underlying cash flows.

Emera Energy has a number of Asset Management Agreements ("AMAs") with local gas distribution utilities ("LDCs") in the northeast. The AMAs involve Emera Energy supplying gas to the LDCs for a specific term, and the corresponding release of utility owned gas transportation/storage capacity to Emera Energy. Mark-to-market adjustments on these AMA's arise on the price differential between the point where gas is sourced and where it is delivered. At inception, the MTM adjustment is offset fully by the corresponding transportation asset, which is amortized over the term of the AMA contract. Subsequent changes in gas price differentials, to the extent not offset by the accounting amortization of the transportation asset, will result in MTM gains or losses recorded in income. MTM adjustments may be substantial in the early months of a contract when delivered volumes and market volatility are usually at peak levels. As a contract is realized, and volumes reduce, volatility is expected to decrease. Ultimately, the transportation asset and the mark-to-market adjustment reduce to zero at the end of the contract term. As the business grows, and AMA volumes increase, MTM volatility resulting in gains and losses may also increase.

# Review of 2015

**Emera Energy Adjusted Contribution to Consolidated Net Income**

| For the<br>millions of Canadian dollars (except per share amounts) | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Trading and marketing margin (1) | **$ 38.0** | $ 15.8 | **$ 84.9** | $ 117.5 | $ 60.3 |
| Electricity sales (2) | **142.5** | 102.4 | **545.9** | 520.7 | 146.2 |
| **Total operating revenues – non-regulated** | **180.5** | 118.2 | **630.8** | 638.2 | 206.5 |
| Non-regulated fuel for generation and purchased power (3) | **86.5** | 61.6 | **334.9** | 384.8 | 97.9 |
| Operating, maintenance and general | **25.3** | 16.6 | **79.7** | 78.7 | 43.6 |
| Provincial, state and municipal taxes | **2.3** | 1.2 | **6.6** | 5.5 | 0.8 |
| Depreciation and amortization | **10.8** | 8.9 | **40.6** | 37.7 | 11.2 |
| Total operating expenses | **124.9** | 88.3 | **461.8** | 506.7 | 153.5 |
| **Adjusted income (loss) from operations** | **55.6** | 29.9 | **169.0** | 131.5 | 53.0 |
| Income from equity investments (4) | **3.2** | 1.6 | **26.4** | 12.3 | 17.1 |
| Other income (expenses), net | **1.2** | 0.8 | **25.1** | 2.9 | 0.2 |
| Interest expense, net | **6.1** | 1.4 | **19.3** | 6.2 | 1.0 |
| **Adjusted income (loss) before provision for income taxes** | **53.9** | 30.9 | **201.2** | 140.5 | 69.3 |
| Income tax expense (recovery) (5) | **18.5** | 9.6 | **71.1** | 42.3 | 24.2 |
| **Adjusted contribution to consolidated net income (loss)** | **$ 35.4** | $ 21.3 | **$ 130.1** | $ 98.2 | $ 45.1 |
| After-tax derivative mark-to-market gain (loss) | **$ 4.3** | $ 72.7 | **$ (31.2)** | $ 87.5 | $ (41.9) |
| **Contribution to consolidated net income** | **$ 39.7** | $ 94.0 | **$ 98.9** | $ 185.7 | $ 3.2 |
| Adjusted contribution to consolidated earnings per common share – basic | **$ 0.24** | $ 0.15 | **$ 0.89** | $ 0.69 | $ 0.34 |
| Contribution to consolidated earnings per common share – basic | **$ 0.27** | $ 0.65 | **$ 0.68** | $ 1.30 | $ 0.02 |
| | | | | | |
| Adjusted EBITDA | **$ 70.8** | $ 41.2 | **$ 261.1** | $ 184.4 | $ 81.5 |

(1) Trading and marketing margin excludes a pre-tax mark-to-market gain of $37.4 million in Q4 2015 (2014 - $84.6 million gain) and a loss of $1.8 million for the year ended December 31, 2015 (2014 - $119.9 million gain)
(2) Electricity sales exclude a pre-tax mark-to-market loss of $21.9 million in Q4 2015 (2014 – $44.6 million gain) and a loss of $39.1 million for the year ended December 31, 2015 (2014 - $42.8 million gain)
(3) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market loss of $5.4 million in Q4 2015 (2014 – $17.9 million loss) and a loss of $6.3 million for the year ended December 31, 2015 (2014 - $20.8 million loss)
(4) Income from equity investments excludes a pre-tax mark-to-market loss of $9.7 million in Q4 2015 (2014 - $3.6 million loss) and a loss of $5.6 million for the year ended December 31, 2015 (2014 - $13.2 million loss)
(5) Income tax expense (recovery) excludes a $3.9 million recovery relating to mark-to-market gains in Q4 2015 (2014 - $35.0 million expense) and $21.6 million recovery relating to mark-to-market losses for the year ended December 31, 2015 (2014 - $41.2 million expense)

Emera Energy's contribution to consolidated net income decreased by $54.3 million to $39.7 million in Q4 2015 compared to $94.0 million in Q4 2014. For the year ended December 31, 2015, Emera Energy's contribution to consolidated net income decreased $86.8 million to $98.9 million compared to $185.7 million in 2014. Highlights of the income changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2013** | | **$ 3.2** |
| Increased trading and marketing margin primarily due to very strong market conditions in northeastern United States and Ontario in Q1 2014 and a stronger USD | | 57.2 |
| Increased electricity sales primarily due to the acquisition of the New England Gas Generating Facilities in November 2013, higher power prices and increased sales at Bayside Power | | 374.5 |
| Increased non-regulated fuel for generation and purchased power primarily due to the acquisition of the New England Gas Generating Facilities in November 2013, higher commodity prices and increased generation at Bayside Power | | (286.9) |
| Increased OM&G primarily due to the acquisition of the New England Gas Generating Facilities and increased performance-based compensation accruals resulting from increased trading and marketing margin | | (35.1) |
| Increased depreciation and amortization primarily due to the acquisition of the New England Gas Generating Facilities | | (26.5) |
| Income from equity investments reflects a non-recurring gain on the settlement of warranty obligations related to certain NWP turbines, decreased curtailments at NWP, recognition of business interruption insurance proceeds related to a 2013 outage at Bear Swamp and favourable pricing at Bear Swamp | | (4.8) |
| Increased income tax expense primarily due to increased income before provision for taxes | | (18.1) |
| Increased mark-to-market gains, net of tax, primarily due to the reversal of 2013 mark-to-market losses and changes in gas and power contract positions, as well as favourable power contracts at the New England Gas Generating Facilities | | 129.4 |
| Other | | (7.2) |
| **Contribution to consolidated net income – 2014** | **$ 94.0** | **$ 185.7** |
| Increased (decreased) trading and marketing margin – See Trading and Marketing Margin section below | 22.2 | (32.6) |
| Increased electricity sales quarter-over-quarter primarily due to higher sales volumes, reflecting reduced generation for planned outage work at Bridgeport in Q4 2014, which reduced generation and a stronger USD; year-over-year is also partially offset by lower power prices | 40.1 | 25.2 |
| Increased non-regulated fuel for generation and purchased power quarter-over-quarter as a result of higher sales volumes, reflecting reduced generation for planned outage work at Bridgeport in Q4 2014 and a stronger USD; year-over-year reduction is primarily due to lower commodity fuel prices, partially offset by a stronger USD | (24.9) | 49.9 |
| Increased OM&G quarter-over-quarter primarily due to timing of maintenance work at the New England Gas Generating Facilities, the stronger USD and increased performance-based compensation resulting from increased trading and marketing margins; year-over-year primarily due to stronger USD, offset by decreased performance-based compensation resulting from decreased trading and marketing margins | (8.7) | (1.0) |
| Increased income from equity investments – See "Equity Investments" below | 1.6 | 14.1 |
| Increased other income (expenses) year-over-year primarily due to a gain on the sale of NWP | 0.4 | 22.2 |
| Increased interest expense, net primarily due to higher interest rates on internal financing | (4.7) | (13.1) |
| Increased income tax expense primarily due to increased income before provision for income taxes; year-over-year increase also due to changes in the proportion of income earned in higher tax rate foreign jurisdiction and a stronger USD | (8.9) | (28.8) |

| | | | |
|---|---|---|---|
| Decreased mark-to-market, net of tax, quarter-over-quarter primarily due to changes in gas and power contract positions, and amortization of transportation assets; decreased year-over-year also due to the reversal of 2013 mark-to-market losses in 2014 | | (68.4) | (118.7) |
| Other | | (3.0) | (4.0) |
| **Contribution to consolidated net income – 2015** | **$** | **39.7 $** | **98.9** |

A portion of earnings are exposed to foreign exchange fluctuations thereby impacting adjusted CAD contribution to net earnings. The impact of a stronger USD, quarter-over-quarter increased earnings in CAD dollars by $3.4 million in Q4 2015 compared to 2014. For the year ended December 31, 2015 the impact of a stronger USD increased earnings in CAD dollars by $11.9 million compared to the same period in 2014.

## Energy Services

Emera Energy Services derives revenue and earnings from the wholesale trading and marketing of natural gas, electricity and other energy-related commodities and derivatives within the Company's risk tolerances, including those related to value-at-risk ("VaR") and credit exposure. Emera Energy purchases and sells physical natural gas and related transportation capacity rights, as well as providing related energy asset management services. EES is also responsible for commercial management of electricity production and fuel procurement for Emera Energy Generation's fleet. Established in 2002, Emera Energy's trading and marketing business currently has approximately 80 employees engaged in commercial activities and related back office, legal and other support functions. The primary market for the trading and marketing business is northeastern North America, including the Marcellus shale gas region, the US Gulf Coast and Central Canada. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. Trading and marketing operates in a competitive environment, and its business relies on knowledge of the region's energy markets, understanding of pipeline infrastructure, a network of counterparty relationships and a focus on customer service. Emera Energy manages its commodity risk by limiting open positions, utilizing financial products to hedge purchases and sales, and investing in transportation capacity rights to enable movement across its portfolio.

### Adjusted EBITDA

Adjusted EBITDA for Emera Energy's trading and marketing business is summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Trading and marketing margin | **$ 38.0** | $ 15.8 | **$ 84.9** | $ 117.5 | $ 60.3 |
| OM&G | **7.9** | 5.0 | **21.3** | 24.8 | 15.2 |
| Other income (expenses), net | **1.0** | 0.8 | **5.6** | 2.6 | 1.0 |
| Adjusted EBITDA | **$ 31.1** | $ 11.6 | **$ 69.2** | $ 95.3 | $ 46.1 |

**Trading and Marketing Margin**

Trading and marketing margin is comprised of Emera Energy's corresponding purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management services' revenues.

Trading and marketing margin increased $22.2 million to $38.0 million in Q4 2015 compared to $15.8 million in Q4 2014. This reflects growth in the volume of business, including increased investment in transportation capacity, the value of which is primarily realized in the winter months. For the year ended December 31, 2015, trading and marketing margin decreased $32.6 million to $84.9 million compared to $117.5 million in 2014. Q1 2014 saw sustained high pricing and volatility in several of Emera Energy's markets, largely the result of cold weather. Subsequently, there was a return to more normal market conditions. Trading and marketing margins were also favourably affected by the strengthening USD in Q4 2015 and for the year ended December 31, 2015.

## Generation

Emera Energy wholly owns and operates a portfolio of high efficiency, non-utility electricity generating facilities in northeast North America.

Information regarding Emera Energy's wholly owned generation facilities is summarized in the following table:

| Wholly Owned Generation Facilities | Location | Capacity (MW) | Commissioning/ In-Service Date | Fuel | Description |
|---|---|---|---|---|---|
| **New England** | | | | | |
| Bridgeport (1) | Connecticut | 560 | 1999 | Natural gas | Selling electricity and capacity to ISO-NE |
| Tiverton | Rhode Island | 265 | 2000 | Natural gas | Selling electricity and capacity to ISO-NE |
| Rumford | Maine | 265 | 2000 | Natural gas | Selling electricity and capacity to ISO-NE |
| **Total New England** | | **1,090** | | | |
| **Maritime Canada** | | | | | |
| Bayside | New Brunswick | 290 | 2001 | Natural gas | Long-term power purchase agreement ("PPA") November - March; Selling electricity to Maritimes and ISO-NE for remainder of year |
| Brooklyn | Nova Scotia | 30 | 1996 | Biomass | Long-term PPA |
| **Total Maritime Canada** | | **320** | | | |
| **Total EEG** | | **1,410** | | | |

(1) A Q2 2015 upgrade at Bridgeport increased its nameplate capacity from 540 MW to 560 MW.

Emera Energy has approximately 125 employees in its generation business. For the portion of output not committed under PPAs, Emera Energy's generation facilities sell into price-based competitive markets and earn revenues through the physical delivery of power and ancillary services, such as load regulation. The New England facilities also participate in the regional capacity market and are compensated for being available to provide power. The electricity generation business in the northeast is seasonal. Q1, Q3 and Q4 are generally the strongest periods, reflecting colder weather, and fewer daylight hours in the winter season, and cooling load in the summer.

**Adjusted EBITDA**

Adjusted EBITDA is summarized in the following table:

| For the | Three months ended December 31 | | | | |
|---|---|---|---|---|---|
| | New England | | Maritime Canada | | Total | |
| millions of Canadian dollars | **2015** | 2014 | **2015** | 2014 | **2015** | 2014 |
| Energy sales | **$ 110.7** | $ 63.3 | **$ 19.9** | $ 25.8 | **$ 130.6** | $ 89.1 |
| Capacity and other | **11.9** | 13.3 | **-** | - | **11.9** | 13.3 |
| Electricity sales | **122.6** | 76.6 | **19.9** | 25.8 | **142.5** | 102.4 |
| Non-regulated fuel for generation and purchased power | **72.7** | 44.9 | **10.9** | 15.3 | **83.6** | 60.2 |
| Non-regulated electric margin | **49.9** | 31.7 | **9.0** | 10.5 | **58.9** | 42.2 |
| Provincial taxes | **1.3** | 0.9 | **0.2** | 0.2 | **1.5** | 1.1 |
| OM&G | **12.4** | 7.5 | **4.4** | 3.7 | **16.8** | 11.2 |
| Other income (expenses), net | **0.3** | - | **(0.1)** | - | **0.2** | - |
| Adjusted EBITDA | **$ 36.5** | $ 23.3 | **$ 4.3** | $ 6.6 | **$ 40.8** | $ 29.9 |

Adjusted EBITDA is summarized in the following table:

| For the | Year ended December 31 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | New England (1) | | | Maritime Canada (2) | | | Total | | |
| millions of Canadian dollars | **2015** | 2014 | 2013 | **2015** | 2014 | 2013 | **2015** | 2014 | 2013 |
| Energy sales | **$ 413.9** | $ 365.5 | $ 64.0 | **$ 88.3** | $ 109.4 | $ 77.8 | **$ 502.2** | $ 474.9 | $ 141.8 |
| Capacity and other | **43.7** | 45.8 | 4.4 | **-** | - | - | **43.7** | 45.8 | 4.4 |
| Electricity sales | **$ 457.6** | $ 411.3 | $ 68.4 | **$ 88.3** | $ 109.4 | $ 77.8 | **$ 545.9** | $ 520.7 | $ 146.2 |
| Non-regulated fuel for generation and purchased power | **277.3** | 311.8 | 48.6 | **52.2** | 73.5 | 47.3 | **329.5** | 385.3 | 95.9 |
| Non-regulated electric margin | **180.3** | 99.5 | 19.8 | **36.1** | 35.9 | 30.5 | **216.4** | 135.4 | 50.3 |
| Provincial taxes | **4.7** | 4.6 | - | **0.9** | 0.9 | 0.8 | **5.6** | 5.5 | 0.8 |
| OM&G | **37.5** | 29.9 | 7.1 | **18.7** | 21.3 | 19.3 | **56.2** | 51.2 | 26.4 |
| Other income (expenses), net | **1.6** | - | - | **(0.7)** | 0.3 | (0.8) | **0.9** | 0.3 | (0.8) |
| Adjusted EBITDA | **$ 139.7** | $ 65.0 | $ 12.7 | **$ 15.8** | $ 14.0 | $ 9.6 | **$ 155.5** | $ 79.0 | $ 22.3 |

(1) The New England Gas Generating Facilities were acquired in November 2013.
(2) Brooklyn Energy was acquired in July 2013.

Adjusted EBITDA increased $10.9 million to $40.8 million in Q4 2015 from $29.9 million compared to Q4 2014 primarily due to increased generation, reflecting a major planned outage at Bridgeport Energy in Q4 2014. For the year ended December 31, 2015, adjusted EBITDA increased $76.5 million to $155.5 million from $79.0 million in 2014, primarily due to higher margins realized in the New England Gas Generating Facilities, reflecting favourable short-term economic hedges, favourable pricing. The strengthening USD contributed $17.6 million.

Operating Statistics

| For the | Three months ended December 31 | | | | | |
|---|---|---|---|---|---|---|
| | Sales Volumes (GWh) (1) | | Plant Availability (%) (2) | | Net Capacity Factor (%) (3) | |
| | **2015** | 2014 | **2015** | 2014 | **2015** | 2014 |
| New England | **1,194** | 777 | **98.9%** | 62.6% | **49.7%** | 33.4% |
| Maritime Canada | **417** | 525 | **89.5%** | 95.1% | **60.5%** | 76.1% |
| Total | **1,611** | 1,302 | **96.8%** | 70.0% | **52.1%** | 43.2% |

| For the | | | | | Year ended December 31 | |
|---|---|---|---|---|---|---|
| | Sales Volumes (GWh) (1) | | Plant Availability (%) (2) | | Net Capacity Factor (%) (3) | |
| | **2015** | 2014 | **2015** | 2014 | **2015** | 2014 |
| New England | **4,777** | 4,375 | **94.5%** | 79.9% | **50.5%** | 47.6% |
| Maritime Canada | **1,699** | 1,910 | **92.7%** | 91.4% | **61.9%** | 69.9% |
| Total | **6,476** | 6,285 | **94.1%** | 82.6% | **53.0%** | 52.7% |

(1) Sales volumes represent the actual electricity output of the plants.
(2) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running. Effectively, it represents 100% availability reduced by planned and unplanned outages.
(3) Net capacity factor is the ratio of the utilization of an asset as compared to its maximum capability, within a particular time frame. It is generally a function of plant availability and plant economics vis-à-vis the market.

Sales volumes and net capacity factor increased quarter-over-quarter primarily due to the impact of a planned outage and plant upgrade at the Bridgeport facility in Q4 2014; year-over-year increase in sales volumes was primarily due to fewer outage days in 2015 at the New England Gas Generating Facilities.

Upgrades completed in Q2 2015 at the Bridgeport facility, including a new gas turbine rotor and improved combustion system, added 20 MW of capacity, bringing the plant total to 560 MW. Availability has increased at the New England Gas Generating Facilities due to significant reliability and performance-based investment in 2014.

The New England Gas Generating Facilities sell into price based competitive markets. The primary reason that the overall capacity factor is lower for New England Gas Generating Facilities as compared to the Maritime facilities is because the Rumford Power Plant, in particular, generally operates with a capacity factor of approximately 20 per cent, reflecting current electricity and gas supply price dynamics in its markets.

## Equity Investments

Information regarding Emera Energy's equity investments in generation facilities is summarized below:

| Investments in Generation Facilities | Ownership | Location | Capacity (MW) | Fuel | Description |
|---|---|---|---|---|---|
| **New England** | | | | | |
| Bear Swamp | 50 per cent | Massachusetts | 600 | Hydro | Long-term PPA and selling electricity and capacity to ISO-NE |
| NWP (1) | 49 per cent | Maine | 419 | Wind | Long-term PPA and selling electricity to ISO-NE and New York ISO ("NYISO") |
| **Total New England** | | | **1,019** | | |

(1) On January 29, 2015, Emera completed the sale of NWP to First Wind for $223.3 million USD. Emera's carrying value of its 49 per cent interest as at December 31, 2014 was $204.4 million USD.

## Adjusted income from equity investments

Adjusted income from equity investments is summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Bear Swamp | **$ 3.2** | $ 2.4 | **$ 24.5** | $ 19.2 | $ 15.8 |
| NWP | **-** | (0.8) | **1.9** | (6.9) | 1.3 |
| Adjusted income from equity investments | **$ 3.2** | $ 1.6 | **$ 26.4** | $ 12.3 | $ 17.1 |

Adjusted Income from equity investments increased $1.6 million to $3.2 million in Q4 2015 compared to $1.6 million in Q4 2014 primarily due to transmission line outages that negatively affected power sales at Bear Swamp in 2014, partially offset by higher interest costs as a result of its Q4 2015 refinancing. For the year ended December 31, 2015, adjusted income from equity investments increased $14.1 million to $26.4 million compared to $12.3 million in 2014. This was primarily due to the resupply of the contracted power sales in Bear Swamp in 2015 that were not delivered in 2014 due to transmission line outages, NWP losses recorded in 2014 and the strengthening USD.

## Other Income

On January 29, 2015, Emera completed the sale of its 49 per cent interest in NWP for $282.3 million ($223.3 million USD). This sale resulted in a pre-tax gain of $18.6 million or $0.13 per common share (after-tax gain of $11.5 million or $0.08 per common share), which was recorded in “Other income (expenses), net” on the Consolidated Statements of Income in Q1 2015.

## Income Taxes

Emera Energy is subject to corporate income tax at the statutory rate ranging from 39.2 to 41.5 per cent (combined US federal and state income tax rate) on its US sourced income and ranging from 27.0 to 31.0 per cent (combined Canadian federal and provincial income tax rate) on its Canada sourced income.

New England Gas Generating Facilities is subject to corporate income tax at the statutory rate ranging from 35.0 to 40.9 per cent (combined US federal and state income tax rate).

Brooklyn Energy is subject to corporate income tax at the statutory rate of 31.0 per cent (combined Canadian federal and provincial income tax rate).

## Bear Swamp Refinancing

On October 8, 2015, Bear Swamp refinanced its $125 million USD bank debt that was due to mature in 2017 and issued $400 million USD in senior secured 10-year bonds, with $375 million USD at fixed rate of 4.89 per cent and $25 million USD at a floating rate of LIBOR plus 2.70 per cent. The proceeds of this financing were used to repay existing debt and provide working capital to the joint venture, with the remainder shared equally between Emera and its joint venture partner. After fees and expenses, Emera received a $178.7 million ($137.3 million USD) non-taxable distribution in Q4 2015.

# CORPORATE AND OTHER

## Corporate

Corporate includes certain corporate-wide functions including executive management, strategic planning, treasury services, financial reporting, tax planning, corporate business development, corporate governance, internal audit, investor relations, risk management, insurance, acquisition related costs and corporate human resource activities. It also includes interest revenue on intercompany financings recorded in "Intercompany revenue" in the table below, and costs associated with corporate activities that are not directly allocated to the operations of Emera's consolidated subsidiaries and investments.

## Other

Other includes the following consolidated and non-consolidated investments:

**Consolidated Investments**

- Emera Utility Services is a utility services contractor primarily operating in Atlantic Canada (recorded in "Non-regulated operating revenue" in the table below).

- Emera Reinsurance Limited is a captive insurance company providing insurance and reinsurance to Emera and its affiliates, to enable more cost efficient management of risk and deductible levels across Emera (recorded in "OM&G" and "Other income (expenses), net" in the table below).

**Non-consolidated investments** (recorded in "Income (loss) from equity investments" in the table below)

- Emera's 23.4 per cent investment in APUC, including outstanding subscription receipts and associated dividend equivalents. APUC is a diversified generation, transmission and distribution utility traded on the Toronto Stock Exchange ("TSX") under the symbol "AQN". The distribution group operates in the United States and provides rate regulated water, electricity and natural gas utility services. The non-regulated generation group owns or has interests in a portfolio of North American-based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission group invests in rate-regulated electric transmission and natural gas pipeline systems in the United States and Canada. The investment in APUC is accounted for on the equity basis. There is a one quarter lag in reporting as APUC's information is generally not publicly available at the time of Emera's public release of its financial results. As at December 31, 2015, Emera owned 50.1 million common shares, 12.6 million outstanding subscription receipts and dividend equivalents, at an average conversion price of $9.20. The outstanding subscription receipts became eligible for conversion into APUC common shares at Emera's election in Q4 2015 and will automatically convert to common shares in Q4 2016 if an election is not made. The subscription receipts are now included in "Investments subject to significant influence" on the Consolidated Balance Sheets.

- Emera's 100 per cent investment in ENL, which holds investments in the following:

    - Emera's 100 per cent investment in NSPML, a $1.56 billion transmission project, including two 170-kilometre subsea cables, between the island of Newfoundland and Nova Scotia. The investment in NSPML is accounted for on the equity basis with equity earnings equal to the return on equity component of AFUDC. This will continue until the Maritime Link Project goes into service, which is expected in 2017.

    - Emera's 55.1 per cent investment in the partnership capital of LIL, a $3.1 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera's percentage ownership in LIL is subject to change based on the balance of capital investments required from Emera and Nalcor to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined on completion of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments. The investment in LIL is accounted for on the equity basis. This project is expected to go into service in 2017.

- Emera's 3.3 per cent investment in Open Hydro is accounted for on the cost basis.

- Other investments.

**Mark-to-Market Adjustments**

Specific to the pending TECO Energy acquisition, Emera has recorded after-tax mark-to-market gains of $100.5 million for the three months and year ended December 31, 2015 (2014 – nil) related to the effect of USD-denominated currency and forward contracts put in place to hedge the anticipated proceeds from the second instalment of the Debenture Offering of the pending acquisition, expected mid-2016.

"Other income (expenses), net" and "Income tax expense (recovery)" are affected by the mark-to-market adjustments discussed above. Corporate and Other's income table below shows these amounts net of mark-to-market adjustments and details the adjustments in the footnotes.

# Review of 2015

**Corporate and Other**

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Intercompany revenue (1) | **$ 9.9** | $ 6.8 | **$ 34.2** | $ 26.0 | $ 38.3 |
| Non-regulated operating revenue | **9.9** | 16.1 | **40.1** | 48.7 | 43.5 |
| Non-regulated direct costs | **9.9** | 15.2 | **42.4** | 46.9 | 44.6 |
| Operating, maintenance and general | **32.7** | 16.8 | **104.1** | 46.2 | 39.0 |
| Depreciation and amortization | **0.7** | 0.5 | **1.7** | 2.3 | 3.8 |
| Total operating expenses | **43.3** | 32.5 | **148.2** | 95.4 | 87.4 |
| **Income (loss) from operations** | **(23.5)** | (9.6) | **(73.9)** | (20.7) | (5.6) |
| Income (loss) from equity earnings | **25.5** | 11.6 | **61.3** | 46.3 | 3.3 |
| Other income (expenses), net (2) | **(5.0)** | (0.1) | **(4.3)** | 3.2 | 16.9 |
| Interest expense | **29.5** | 6.3 | **48.1** | 30.9 | 37.5 |
| **Adjusted income (loss) before provision for income taxes** | **(32.5)** | (4.4) | **(65.0)** | (2.1) | (22.9) |
| Income tax expense (recovery) (3) | **(15.5)** | (5.2) | **(40.1)** | (20.6) | (28.4) |
| Preferred stock dividends | **-** | - | **30.3** | 26.2 | 19.3 |
| **Adjusted contribution to consolidated net income** | **$ (17.0)** | $ 0.8 | **$ (55.2)** | $ (7.7) | $ (13.8) |
| After-tax mark-to-market gain (loss) | **100.5** | - | **100.5** | - | - |
| **Contribution to consolidated net income** | **$ 83.5** | $ 0.8 | **$ 45.3** | $ (7.7) | $ (13.8) |
| Adjusted contribution to consolidated earnings per common share – basic | **$ (0.12)** | $ 0.01 | **$ (0.38)** | $ (0.05) | $ (0.10) |
| Contribution to consolidated earnings per common share – basic | **$ 0.57** | $ 0.01 | **$ 0.31** | $ (0.05) | $ (0.10) |
| | | | | | |
| Adjusted EBITDA | **$ (2.3)** | $ 2.4 | **$ (15.2)** | $ 31.1 | $ 18.4 |

(1) Intercompany revenue consists of interest from Brunswick Pipeline, M&NP and EEG.

(2) Other income (expenses) net, excludes a pre-tax mark-to-market gain of $118.9 million in Q4 2015 and for the year ended December 31, 2015 compared to nil for the same periods in 2014.

(3) Income tax expense (recovery), excludes an $18.4 million expense relating to mark-to-market gains in Q4 2015 and for the year ended December 31, 2015 compared to nil for the same periods in 2014.

Corporate and Other's contribution to consolidated net income increased by $82.7 million to $83.5 million in Q4 2015 compared to $0.8 million in Q4 2014. For the year ended December 31, 2015, Corporate and Other's contribution to consolidated net income increased $53.0 million to $45.3 million compared to $(7.7) million in 2014. Highlights of the income changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2013** | | **$ (13.8)** |
| Decreased intercompany revenue primarily due to lower interest revenue resulting from the repayment of NWP loan in November 2013 | | (12.3) |
| Increased OM&G primarily due to higher deferred compensation costs, partially offset by lower business development costs | | (7.2) |
| Income from equity investments – see table below for highlights | | 43.0 |
| Decreased other income primarily due to the 2013 gains on the exchange of APUC subscription receipts to common shares, partially offset by the 2013 AHI investment impairment | | (13.7) |
| Decreased interest expense primarily due to lower short-term debt levels | | 6.6 |
| Increased income tax expense primarily due to increased income before provision for income taxes | | (7.8) |
| Increased preferred stock dividends primarily due to an incremental preferred share issuance | | (6.9) |
| Other | | 4.4 |
| **Contribution to consolidated net income – 2014** | **$ 0.8** | **$ (7.7)** |
| Increased intercompany revenue due to the issuance of a loan to Emera Energy Generation, partially offset by the repayment of an intercompany loan from Brunswick Pipeline | 3.1 | 8.2 |
| Acquisition costs related to the pending TECO Energy acquisition | (21.0) | (51.5) |
| Decreased OM&G quarter-over-quarter primarily due to lower performance-based compensation; increased year-over-year primarily due to business development costs not related to the pending TECO Energy acquisition | 5.1 | (6.4) |
| Income from equity investments – see Income from Equity Investments section below | 13.9 | 15.0 |
| Decreased other income quarter-over-quarter due to the reclassification of APUC subscription receipts; year-over-year due to the losses incurred in Emera Reinsurance from Tropical Storm Erika and the recognition of NSPML as an equity investment in Q2 2014 | (4.9) | (7.5) |
| Increased interest expense primarily due to interest on convertible debentures represented by installment receipts, partially offset year-over-year by maturity of long-term debt in Q4 2014 | (23.2) | (17.2) |
| Decreased income tax expense primarily due to the decreased income before provision for income taxes | 10.3 | 19.5 |
| Increased preferred stock dividends year-over-year primarily due to issuance of preferred shares in Q2 2014 | - | (4.1) |
| After-tax mark-to-market gain (loss) – see After-Tax Mark-to-Market Gain (Loss) section below | 100.5 | 100.5 |
| Other | (1.1) | (3.5) |
| **Contribution to consolidated net income – 2015** | **$ 83.5** | **$ 45.3** |

## Acquisition Related Costs

Highlights of the acquisition related costs summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | 2013 |
| Operating, maintenance, and general | **$ 21.0** | $ - | **$ 51.5** | $ - | $ - |
| Interest expense, net | **23.3** | - | **23.9** | - | - |
| Income tax expense (recovery) | **(14.0)** | - | **(22.6)** | - | - |
| Acquisition related costs | **$ 30.3** | $ - | **$ 52.8** | $ - | $ - |

### After-Tax Mark-to-Market Gain (Loss)

The foreign currency earnings impact related to the translation gain from the convertible debenture USD cash balance and the mark-to-market gain from forward contracts from economically hedging the Debenture Offering are recorded as a mark-to-market adjustment. These pre-tax earnings impacts totaled $118.9 million in "Other income (expenses), net" on the Consolidated Statements of Income ($100.5 million after-tax). The after-tax mark-to-market gain (loss) related to the pending acquisition of TECO Energy is summarized in the following table:

| For the<br>millions of Canadian dollars | | Three months ended<br>December 31 | | | Year ended<br>December 31 | |
|---|---|---|---|---|---|---|
| | | **2015** | 2014 | **2015** | 2014 | 2013 |
| Foreign exchange on USD cash | **$** | **26.8** $ | - **$** | **26.8** $ | - $ | - |
| Mark-to-market adjustment on USD forward contracts | | **92.1** | - | **92.1** | - | - |
| Income tax expense (recovery) | | **(18.4)** | - | **(18.4)** | - | - |
| After-tax mark-to-market gain (loss) | **$** | **100.5** $ | - **$** | **100.5** $ | - $ | - |

### Income from Equity Investments

Income from equity investments are summarized in the following table:

| For the<br>millions of Canadian dollars | | Three months ended<br>December 31 | | | Year ended<br>December 31 | |
|---|---|---|---|---|---|---|
| | | **2015** | 2014 | **2015** | 2014 | 2013 |
| APUC | **$** | **18.0** $ | 5.6 **$** | **36.9** $ | 30.4 $ | 0.4 |
| NSPML | | **3.8** | 4.4 | **14.9** | 9.5 | - |
| LIL | | **3.7** | 1.6 | **9.5** | 6.4 | 5.2 |
| AHI | | **-** | - | **-** | - | (2.3) |
| Income from equity investments | **$** | **25.5** $ | 11.6 **$** | **61.3** $ | 46.3 $ | 3.3 |

Income from equity investments increased $13.9 million to $25.5 million in Q4 2015 compared to $11.6 million in Q4 2014. For the year ended December 31, 2015, income from equity investments increased $15.0 million to $61.3 million compared to $46.3 million in 2014. Highlights of the income changes are summarized in the following table:

| For the<br>millions of Canadian dollars | | Three months ended<br>December 31 | | Year ended<br>December 31 |
|---|---|---|---|---|
| **Income from equity investments – 2013** | | | **$** | **3.3** |
| APUC – Increased due to dilution gains resulting from share issuances, higher earnings and 2013 recognition of discontinued operations of $8.3 million | | | | 30.0 |
| NSPML – Recognition of the AFUDC earnings of NSPML as income from equity investment | | | | 9.5 |
| Other | | | | 3.5 |
| **Income from equity investments – 2014** | **$** | **11.6** | **$** | **46.3** |
| APUC – Increased quarter-over-quarter primarily due higher equity earnings in 2015, the reclassification of APUC subscription receipts in 2015 and a higher dilution gain from the share issuance in Q4 2015 compared to dilution gain from share issuance in Q4 2014; year-over-year due to higher equity earnings in 2015, the reclassification of APUC subscription receipts in 2015, partially offset by lower dilution on APUC share issuances in 2015 compared to dilutions related to share issuances in 2014 | | 12.4 | | 6.5 |
| NSPML – Increased year-over-year due to the recognition of the AFUDC earnings of NSPML as income from equity investment | | (0.6) | | 5.4 |
| LIL – Increase in investment | | 2.1 | | 3.1 |
| **Income from equity investments – 2015** | **$** | **25.5** | **$** | **61.3** |

NSPML has cumulatively invested $693.9 million of equity and debt, including $78.1 million of AFUDC, in the development of the Maritime Link Project. Project to date, ENL has invested a total of $154.9 million in equity, with the remaining costs being funded with working capital and debt, which has been guaranteed by the Government of Canada. AFUDC on invested equity is being capitalized at an annual rate of 9 per cent. Proceeds from the federally guaranteed debt financing completed in April 2014 were used to fund project costs until the Project's debt to equity ratio reached 70 per cent to 30 per cent respectively, which occurred in Q4 2015. From that point forward, project costs are funded with debt and equity at a 70 per cent to 30 per cent ratio, with equity contributions of $13.4 million in Q4 2015.

Project to date, ENL has invested $207.3 million of equity, including $21.2 million of equity earnings, in LIL. Equity earnings are recorded based on an annual rate of 8.8 per cent of the equity invested. The rate is approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities.

# LIQUIDITY AND CAPITAL RESOURCES

The Company generates cash primarily through its investments in various regulated and non-regulated energy related entities and investments. Utility customer bases are diversified by both sales volumes and revenues among customer classes. Emera's non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company's ability to generate cash include general economic downturns in Emera's markets, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets and changes in environmental legislation. Emera's subsidiaries maintain solid credit metrics and are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment.

# Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the years ended December 31, 2015 and 2014 include:

| Year ended December 31<br>millions of Canadian dollars | | 2015 | | 2014 | | $ Change |
|---|---|---|---|---|---|---|
| Cash and cash equivalents, beginning of period | **$** | **221.1** | $ | 100.8 | $ | 120.3 |
| **Provided by (used in):** | | | | | | |
| Operating cash flow before changes in working capital | | **775.8** | | 716.3 | | 59.5 |
| Change in working capital | | **(101.6)** | | 46.2 | | (147.8) |
| Operating activities | | **674.2** | | 762.5 | | (88.3) |
| Investing activities | | **(123.7)** | | (710.9) | | 587.2 |
| Financing activities | | **221.1** | | 58.2 | | 162.9 |
| Effect of exchange rate changes on cash and cash equivalents | | **80.7** | | 10.5 | | 70.2 |
| Cash and cash equivalents, end of period | **$** | **1,073.4** | $ | 221.1 | $ | 852.3 |

### Operating Cash Flows

Refer to Consolidated Income Statement Highlights for details.

### Investing Cash Flows

Net cash used in investing activities decreased $587.2 million to $123.7 million for the year ended December 31, 2015 compared to $710.9 million for the year ended December 31, 2014. The decrease was primarily due to proceeds from the sale of NWP in 2015, proceeds from the Bear Swamp distribution, purchase of APUC subscription receipts in 2014 and higher levels of investment in NSPML and M&NP in 2014, partially offset by increased capital spend and Emera Maine's investment in a customer information system.

Capital expenditures, including AFUDC and net of proceeds from disposal of assets, for the year ended December 31, 2015 were $436 million compared to $462 million in 2014 primarily due to decreased capital spending in Emera Energy and Emera Maine, partially offset by increased capital spending at Emera Caribbean. Details of the capital spend are shown below:

- $274 million in NSPI (2014 - $274 million);
- $66 million in Emera Maine (2014 - $85 million);
- $44 million in Emera Caribbean (2014 - $30 million);
- $42 million in Emera Energy (2014 - $63 million);
- $10 million in Corporate and Other (2014 – $10 million)

### Financing Cash Flows

Net cash provided by financing activities increased $162.9 million to $221.1 million for the year ended December 31, 2015 compared to $58.2 million in December 31, 2014. The increase was primarily due to the proceeds of convertible debentures represented by instalment receipts related to the pending acquisition of TECO Energy, net of issuance costs, of $681.4 million and the proceeds of the long-term debt issuance by Brunswick Pipeline and NSPI. This was partially offset by the redemption of NSPI's preferred shares, repayment of debt in 2015 and the issuance of common and preferred stock in Q1 2014.

## Working Capital

As at December 31, 2015, Emera's cash and cash equivalents were $ 1,073.4 million (2014 – $221.1 million) and Emera's investment in non-cash working capital was $599.2 million (2014 – $358.3 million). Of the $ 1,073.4 million of cash and cash equivalents held at December 31, 2015, $727.6 million is from the proceeds from the convertible debentures for the pending TECO Energy acquisition and are held in USD. Of the remaining cash and cash equivalents, $373.2 million is held by Emera's foreign subsidiaries (2014 – $206.0 million). A portion of these funds are invested in countries that have certain exchange controls, required approvals, and processes for repatriation. Such funds remain available to fund local operating and capital requirements unless repatriated.

Emera's future liquidity and capital needs will be predominately for working capital requirements and capital expenditures in support of growth throughout the businesses, as well as acquisitions, dividends and debt servicing. These liquidity and capital needs will be financed through internally generated cash flows, short-term credit facilities, and ongoing access to debt and equity capital markets.

## Contractual Obligations

As at December 31, 2015, commitments for each of the next five years and in aggregate thereafter consisted of the following:

| millions of Canadian dollars | 2016 | 2017 | 2018 | 2019 | 2020 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Long-term debt | $ 274.0 | $ 53.0 | $ 25.5 | $ 619.6 | $ 728.7 | $ 2,323.6 | $ 4,024.4 |
| Purchased power (1) | 221.7 | 235.0 | 208.6 | 203.1 | 199.4 | 2,462.8 | 3,530.6 |
| Coal, biomass, oil and natural gas supply | 150.2 | 82.1 | 12.2 | - | - | - | 244.5 |
| DSM (2) | 24.7 | 34.0 | 34.9 | - | - | - | 93.6 |
| Pension and post-retirement obligations (3) | 14.8 | 19.2 | 19.8 | 20.2 | 20.9 | 716.7 | 811.6 |
| Asset retirement obligations | 5.5 | 4.0 | 4.3 | 4.2 | 1.7 | 317.2 | 336.9 |
| Interest payment obligations (4) | 187.7 | 178.8 | 176.3 | 175.3 | 141.3 | 2,249.9 | 3,109.3 |
| Convertible debentures represented by instalment receipts (5) | 727.6 | - | - | - | - | - | 727.6 |
| Interest obligations on the first instalment of convertible debentures represented by instalment receipts (5) | 75.9 | - | - | - | - | - | 75.9 |
| Transportation (6) | 183.6 | 72.2 | 55.8 | 25.7 | 20.9 | 86.9 | 445.1 |
| Long-term service agreements (7) | 56.6 | 45.0 | 33.6 | 55.7 | 18.4 | 207.1 | 416.4 |
| Capital projects | 68.9 | 7.1 | - | - | - | - | 76.0 |
| Equity investment commitments (8) | 379.6 | 159.0 | - | - | - | - | 538.6 |
| Leases and other (9) | 12.6 | 11.6 | 9.5 | 8.9 | 7.5 | 27.5 | 77.6 |
| | $ 2,383.4 | $ 901.0 | $ 580.5 | $ 1,112.7 | $ 1,138.8 | $ 8,391.7 | $ 14,508.1 |

(1) Purchased power: annual requirement to purchase 20 - 100 per cent of electricity production from independent power producers over varying contract lengths up to 25 years.

(2) DSM: program is expected to continue however no amounts have been committed after 2018.

(3) Pension and post-retirement obligations: Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2015. Credited service and earnings are assumed to be crystallized as at December 31, 2015. The Company contractual obligations for post-retirement (non-pension) benefits assumes members must be age 55 or over as at December 31, 2015 to be eligible. As the defined benefit pension plans currently undergoes regular reviews to revise contribution requirements and members are still accruing service under the plans, actual future contributions to the plans will differ from the amounts shown.

(4) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2015 including any expected required payment under associated swap agreements.

(5) Convertible debentures: On September 28, 2015, to finance a portion of the pending acquisition of TECO Energy, Emera completed the sale of $1.9 billion principal amount of 4 per cent convertible unsecured subordinated debentures. On October 2, 2015 the over-allotment option was exercised and $285 million in additional Debentures were sold. The table above shows the obligations as a result of this Debenture Offering. Further information on the Debenture Offering is in the Developments section.

(6) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on various pipelines.

(7) Long-term service agreements: maintenance of certain generating equipment, services related to a generation facility and wind operating agreements, outsourced management of computer and communication infrastructure and vegetation management.

(8) Emera has a commitment in connection with the Federal Loan Guarantee ("FLG") to complete construction of the Maritime Link. Thirty per cent of the financing of this project will come from Emera as equity. Emera also has a commitment to make equity contributions to LIL upon draw requests from the general partner. The amounts forecasted are a combination of equity investments for both projects and are subject to change in both timing and amount as the projects advance through construction.

(9) Leases: operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

## Forecasted Gross Consolidated Capital Expenditures

For the year ended December 31, 2016, forecasted gross consolidated capital expenditures are as follows:

| millions of Canadian dollars | NSPI | Emera Maine | Emera Caribbean | Emera Energy | Corporate and Other | Total |
|---|---|---|---|---|---|---|
| Generation | $ 105.0 | $ - | $ 17.9 | $ 29.9 | $ - | $ 152.8 |
| New renewable generation | - | - | 67.3 | - | - | 67.3 |
| Transmission | 56.1 | 33.6 | 5.9 | - | - | 95.6 |
| Distribution | 74.8 | 34.3 | 38.3 | - | - | 147.4 |
| Facilities, equipment, vehicles, and other | 44.0 | 17.2 | 20.1 | - | 20.4 | 101.7 |
| | $ 279.9 | $ 85.1 | $ 149.5 | $ 29.9 | $ 20.4 | $ 564.8 |

# Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $1.3 billion committed syndicated revolving bank lines of credit, as discussed in the table below. NSPI has an active commercial paper program for up to $400 million, of which the full amount outstanding is backed by the Company's bank line referred to below. The amount of commercial paper issued results in an equal amount of credit being considered drawn and unavailable.

As at December 31, 2015, the Company's total credit facilities, outstanding borrowings and available capacity were as follows:

| millions of dollars | Maturity | Revolving Credit Facilities | Utilized | Undrawn and Available |
|---|---|---|---|---|
| Emera – Operating and acquisition credit facility | June 2020 – Revolver | $ 700 | $ 268 | $ 432 |
| NSPI – Operating credit facility (1) | October 2020 – Revolver | 500 | 370 | 130 |
| Emera Maine – in USD – Operating credit facility | September 2019 – Revolver | 80 | 25 | 55 |
| Other – in USD – Operating credit facilities | Various | 32 | - | 32 |

(1) Extended to October 2020 on December 15, 2015.

For the purpose of bridge financing for the pending acquisition of TECO Energy, on September 4, 2015, the Company secured an aggregate of $6.5 billion USD non-revolving term credit facilities ("Acquisition Credit Facilities") from a syndicate of banks. The non-revolving term credit facilities are comprised of a $4.3 billion USD debt bridge facility, repayable in full on the first anniversary following its advance, and a $2.2 billion USD equity bridge facility repayable in full on the first anniversary following its advance. On October 16, 2015, Emera permanently reduced the USD bridge facilities in the amount of $588.3 million USD with the proceeds of the first instalment of the convertible debentures and the proceeds from the Bear Swamp financing. The credit facilities table above does not include the Acquisition Credit Facilities.

Emera is required to effect reductions or make prepayments of the Acquisition Credit Facilities in an amount equal to the net cash proceeds from any common equity, preferred equity, bond or other debt offerings and any non-ordinary course asset sales by Emera and its subsidiaries, subject to certain prescribed exceptions and certain other prescribed transactions. Net proceeds from any such offerings, including the net proceeds of the final instalment under the Debenture Offering, or from any such non-ordinary course asset sales or transactions, will be applied to permanently reduce the commitments of the lenders under the Acquisition Credit Facilities or to repay the Acquisition Credit Facilities after they are drawn. Any prepayment under the Acquisition Credit Facilities may not be re-borrowed. The Acquisition Credit Agreements will contain customary representations and warranties and affirmative and negative covenants of Emera that will closely resemble those in Emera's existing revolving credit facility.

Emera and its subsidiaries' recent financing activity is discussed further in the Developments section.

As at December 31, 2015, approximately 84 per cent of Emera's consolidated debt position is fixed rate in nature, with an average term to maturity of approximately 17 years. Emera's scheduled maturities for debt over the next five years are expected to be $274 million, $53 million, $25 million, $588 million and $120 million for 2016 through 2020 respectively.

Emera's future liquidity and capital needs, not including the capital needs to fund the pending TECO Energy acquisition, will be predominately for working capital requirements and capital expenditures in support of growth throughout the businesses, as well as potential new acquisitions, dividends and debt servicing. These liquidity and capital needs will be financed through internally generated cash flows, short-term credit facilities, and ongoing access to capital markets.

The cash purchase price of the pending TECO Energy acquisition and the acquisition related costs will be financed at the closing of the acquisition with one or more of the following sources: (i) net proceeds of the first instalment and second instalment under the Debenture Offering, (ii) net proceeds of any subsequently completed preferred equity or bond or other debt offerings, (iii) amounts drawn under the acquisition credit facilities and the revolving facility, and (iv) existing cash on hand and other sources available to the Company. Common equity and other available sources are expected to comprise $1.7 billion USD to $2.1 billion USD of the long-term financing for the acquisition, preferred equity offerings are expected to amount to $0.8 billion USD to $1.2 billion USD and bond or other debt offerings are expected to amount to $3.4 billion USD to $3.8 billion USD.

Emera and its subsidiaries have certain financial and other covenants associated with their debt and credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements. Emera's significant covenant is listed below:

| | **Financial Covenant** | **Requirement** | As at December 31, 2015 |
|---|---|---|---|
| **Emera** | | | |
| Syndicated credit facilities | Debt to capital ratio | Less than or equal to 0.70 to 1 | 0.51:1 |

# Credit Ratings

## Emera

On March 11, 2015, DBRS removed Emera from “Under Review with Developing Implications” following the closing of the Brunswick Pipeline financing and the sale of NWP. On the same date, DBRS confirmed Emera’s Issuer Rating and Medium-Term Notes rating at BBB (high) and the Cumulative Preferred Shares Rating at Pfd-3 (high), all with Stable trends.

On September 4, 2015, following the announcement of the TECO Energy acquisition, DBRS placed the ratings of Emera ‘Under Review with Developing Implications’. The rating actions reflect DBRS’s view that while the TECO Energy acquisition would have a relatively neutral impact on Emera’s business risk assessment, the impact on the financial risk assessment was at the time of the ratings actions uncertain as Emera’s financing plan had not been finalized. DBRS indicated that it will further review Emera’s financing plan when it is finalized.

On September 8, 2015, Standard and Poor’s (“S&P”) revised its outlook on Emera to negative from stable, while affirming all ratings on Emera, including its ‘BBB+’ long-term corporate rating. S&P indicated that the negative outlook is primarily associated with the Debentures and the risk that they will not be converted into equity upon successful close of the acquisition. S&P could revise its outlook to stable within a two-year outlook period, if the Debentures are successfully converted.

Emera’s credit ratings issued by DBRS and S&P are as follows:

| | DBRS | S&P |
|---|---|---|
| Long-term corporate | N/A | BBB+ |
| Senior unsecured debt | BBB (high) | BBB |

## NSPI

On December 18, 2015, DBRS Limited (“DBRS”) affirmed all ratings on NSPI.

On September 8, 2015, Standard and Poor’s Rating Services (“S&P”) affirmed all ratings on NSPI. At the same time it affirmed its rating on Emera and revised Emera’s outlook to negative from stable. The outlook revision for Emera followed Emera’s announcement of the proposed acquisition of TECO Energy. Per S&P’s group rating methodology criteria, NSPI is subject to Emera’s revised outlook.

NSPI’s credit ratings issued by DBRS and S&P are as follows:

| | DBRS | S&P |
|---|---|---|
| Corporate | N/A | BBB+ |
| Senior unsecured debt | A (low) | BBB+ |

Emera Maine, BLPC, Domlec and GBPC have no public debt, and accordingly have no requirement for public credit ratings. These utilities believe their credit facilities provide adequate access to capital to support current operations and a base level of capital expenditures. For additional capital needs, these utilities expect to have sufficient access to competitively priced financing in the unsecured or secured debt markets.

## Share Capital

### Emera

As at December 31, 2015, Emera had 147.21 million (2014 – 143.78 million) common shares issued and outstanding.  For the year ended December 31, 2015, 3.43 million common shares were issued (2014 – 10.89 million) for net proceeds of $141.1 million (2014 – $313.4 million).  The issuance of shares was primarily due to facilitate the creation and issuance of depositary receipts in connection with the ECI share acquisition and the dividend reinvestment program.

On December 17, 2015, Emera issued 1.25 million common shares to facilitate the creation and issuance of 5.0 million depositary receipts in connection with the ECI share acquisition.

As at December 31, 2015, Emera had 29.0 million preferred shares issued and outstanding (2014 – 29.0 million).

# PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values.  This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three-year period.  The cash required in 2016 for defined benefit pension plans is expected to be $19.7 million (2015 – $ 23.0 million).  All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera's defined benefit pension plans employ a long-term strategic approach with respect to asset allocation, real return and risk.  The underlying objective is to earn an appropriate return, given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers per the pension plan's investment policy and governance framework.  The asset allocation includes investments in the assets of Canadian and global equities, domestic and global bonds and short-term investments.  Emera reviews investment manager performance on a regular basis and adjusts the plans' asset mixes as needed in accordance with the pension plans' investment policy.

Emera's projected contributions to defined contribution pension plans are $10.0 million for 2016 (2015 – $9.0 million actual).

**Defined Benefit Pension Plan Summary**
As at December 31, 2015
in millions of Canadian dollars

| **Plans by region** | **NSPI Pension Plans** | **Emera Maine Pension Plans** | **Caribbean Plans** | **Total** |
|---|---|---|---|---|
| Assets as at December 31, 2015 | $ 1,128.6 | $ 161.5 | $ 10.3 | $ 1,300.4 |
| Accounting obligation at December 31, 2015 | 1,295.8 | 211.3 | 12.6 | 1,519.7 |
| Accounting expense during fiscal 2015 | $ 56.1 | $ 6.4 | $ 0.4 | $ 62.9 |

# OFF-BALANCE SHEET ARRANGEMENTS

## Defeasance

Upon privatization of the former provincially owned NSPC in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2015 totaled $0.8 billion (2014 – $0.7 billion). The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), an affiliate of the Province of Nova Scotia. Approximately 70 per cent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

Under the privatization agreements, NSPI administers the defeasance cash flows and obligations pursuant to a Management and Administration Agreement. The NSPFC bank accounts are included in NSPI's pool of bank accounts under a mirror netting agreement and therefore, from time to time, if any cash accumulates in the NSPFC bank account it is available as an offset until that cash is required to service the defeased NSPC debt.

## Guarantees and Letters of Credit

Emera had outstanding the following guarantees and letters of credit on behalf of third parties which are not included within the Consolidated Balance Sheets as at December 31, 2015:

- Emera has provided a completion guarantee to the Government of Canada, whereby it has guaranteed the performance of the obligations of NSPML to cause the completion of the Maritime Link Project, subject to certain conditions set out in that guarantee. The cost of those obligations is estimated to be $1.577 billion, which reduces in the ordinary course as project costs are paid.

- Emera has provided a guarantee to the Long Island Power Authority ("LIPA") on behalf of Bear Swamp for Bear Swamp's long-term energy and capacity supply agreement ("PPA") with LIPA, which expires on April 30, 2021. The guarantee is for 50 per cent of the relevant obligations under the PPA up to a maximum of $5.1 million USD. As at December 31, 2015, the fair value of the PPA was positive.

- Standby letters of credit in the amount of $20.5 million USD for the benefit of secured parties in connection with a refinancing of the Bear Swamp joint venture and also to third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one-year term and are renewed annually as required.

- A standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2016 and is renewed annually. The amount committed as at December 31, 2015 was $42.6 million.

- A standby letter of credit to secure obligations under an unfunded pension plan in Emera Maine. The letter of credit expires in October 2016 and is renewed annually. The amount committed as at December 31, 2015 was $2.7 million USD.

- A standby letter of credit was issued to secure the obligations of Emera Reinsurance Limited under reinsurance agreements. The letter of credit expires in February 2016. The amount committed as at December 31, 2015 was $2.0 million USD.

# OUTLOOK

## General and Market Trends

Energy markets across North America are affected by a number of trends that shape the environment in which energy and utility companies are operating. Some of these trends are short-term or cyclical, while others evolve to have a significant long-term impact on businesses and stakeholders across the sector.

Among the key trends influencing Emera's long-term strategy is the increasing expectation by customers and policy-makers for a permanent reduction in the carbon equivalent levels of electricity generation. This advocacy drive for cleaner, renewable sources of electricity has become a defining trend in the industry, not just in the markets Emera serves, but on a global basis. While it is still unclear whether economic volatility and lower fossil fuel prices will slow the pace of this transformation, its impact on the sector continues to be felt in the form of mandated and incented carbon reductions throughout eastern North America and in the Caribbean. As such, investment in wind, solar and hydro generation, and natural gas infrastructure, is likely to continue across the sector.

This transformation in generation and fuel selection also has a significant impact on the requirement for new transmission infrastructure. Increasingly, in addition to the traditional issues of infrastructure life expectancy and changing technology, infrastructure renewal planning must now take into account the changing energy landscape. Gas extraction from the Marcellus Shale region of the United States, major hydro developments in Newfoundland and Labrador, and wind farms in northern New England and Atlantic Canada (to name a few) require significant new transmission infrastructure to bring this energy to market.

The capital spending requirements related to this renewal underscore the intense focus placed by customers and regulators on electricity price and affordability that is required by our franchise agreements and basic rate regulation. Going forward, the ability of energy companies to achieve their growth objectives, environmental targets and other goals, will continue to be a key success factor.

As technology advances, so too does the availability and demand for affordable new mechanisms that allow consumers to have more control over their energy usage and for utilities to introduce more efficient energy solutions for their customers. This includes grid modernization and 'smart grid' advances that, when combined with in-home products such as heat pumps and electric thermal storage units, have the potential to significantly increase energy efficiency for consumers while allowing utilities to better manage peak load demand. In addition, wind turbine technology and advancements in solar technology have reduced solar generation costs significantly, bringing them more in line with the cost of fossil fuel generation in some higher-cost jurisdictions. This gives rise to an expectation on the part of customers that they will be able to benefit from options such as distributed generation. Continued and advancing development of energy storage technology will further transform and support the efficient and practical utilization of renewables. This, in turn, raises new issues related to the role of the utility, and the appropriate allocation of existing infrastructure and transmission, generation and distribution costs.

These and other trends create opportunities and challenges for businesses, regulators, investors and other stakeholders within the energy sector, and are expected to drive increased regional cooperation and interconnection within the energy industry. Whether it is the need to transport natural gas and electricity from disparate regions to markets on the eastern seaboard, or the need to gain efficiencies by coordinating electricity generation and dispatch across multiple jurisdictions, inter-regional cooperation has emerged as an important trend itself.

## Business Outlook

The pending TECO Energy acquisition will result in further acquisition costs in 2016. The transaction is expected to be accretive to EPS by approximately 5 per cent in the first full year following its completion (2017), growing to more than 10 per cent by the third full year (2019) assuming a USD/CAD exchange rate consistent with that at the time of announcement. As well, approximately 95 per cent of the expected foreign exchange exposure to close the pending acquisition has been actually or effectively hedged.

Emera's operations are affected by the US dollar relative to the Canadian dollar. With the increasing disparity between the two currencies, the effect on Emera's income is noteworthy, as approximately 50 per cent of Emera's adjusted net income was derived from subsidiaries with a US functional currency. TECO Energy operations are conducted in US dollars and following the pending acquisition, Emera's consolidated net income and cash flows will be impacted to a greater extent by movements in the US dollar relative to the Canadian dollar.

# NSPI

NSPI's earnings are most directly impacted by the range of rate of return on equity and capital structure approved by the UARB; the prudent management and approved recovery of operating costs, load, the approved recovery of regulatory deferrals; and the timing and amount of capital expenditures.

NSPI anticipates earning within its allowed ROE range in 2016 and expects its rate base to remain stable. Over the past several years, the requirement to reduce Nova Scotia's reliance upon high carbon and greenhouse gas emitting sources of energy has resulted in NSPI making a significant investments in renewable energy sources and purchasing third party renewable energy.

On November 10, 2015, NSPI announced it does not plan to file a general rate application related to electricity rates for 2016.

In December 2015, the Electricity Plan Act was enacted by the Province of Nova Scotia, with a goal of providing rate stability and predictability for customers for the 2017 through 2019 period. The Electricity Plan Act requires NSPI to file a three-year rate plan for fuel costs in Q1 2016 and to file a three-year application to change non-fuel rates by April 30, 2016, if required by NSPI. NSPI will continue to work towards rate stability for customers through a focused effort on operating costs, productivity levels and service improvements to meet the requirements of the legislation.

The Company expects to finance its capital expenditures with funds from operations, credit facilities and continued access to debt capital markets for long-term financing.

# Emera Maine

Emera Maine's earnings are most directly impacted by the combined impacts of the range of rates of return on equity and rate base approved by its regulators, the prudent management and approved recovery of operating costs, load, and the timing and amount of capital expenditures.

Emera Maine's 2016 ROE is expected to be consistent with prior years. Its ongoing investment in transmission and distribution infrastructure is expected to result in modest growth in rate base.

Emera Maine has an agreement with Central Maine Power Company to pursue specific transmission opportunities in Northern Maine that would relieve transmission congestion and more efficiently collect and deliver wind generation to New England markets. As part of this agreement, Emera Maine and Central Maine Power Company jointly responded to a request for proposals for clean energy from

Massachusetts, Connecticut and Rhode Island, through an existing jointly owned transmission company, Maine Electric Power Company Inc. (“MEPCO”). The demand for this renewable energy is growing as a result of increasing renewable portfolio requirements of the southern New England states.

Future earnings will generally reflect the impact of transmission rate decisions by the FERC. Emera Maine has fully reserved for the refunds required as a result of a FERC decision on the allowed ROE set at 10.57 per cent.

Overall, Emera Maine 2016 USD earnings are expected to be consistent with prior years.

# Emera Caribbean

Earnings from Emera Caribbean are most directly impacted by the combined impacts of the range of rates of return on equity and rate base approved by their regulators, capital structure, the prudent management and approved recovery of operating costs, load, and the timing and amount of capital expenditures. Earnings are also affected by the investment returns of Emera’s interest in BLPC’s self-insurance fund.

The Barbados economy expects growth of approximately 1.8 per cent forecast for 2016. With oil being the predominant fuel source for generation of electricity in the Caribbean, reduced oil prices may result in an economic benefit on the island in decreased cost of electricity to ratepayers. During 2015, BLPC recognized the need to reduce costs in the business to stabilize future rates to customers. BLPC forecasts to maintain the 2015 cost savings into the future.

The economy of Grand Bahamas is highly correlated to the United States economy and has exhibited signs of improving economic growth and a corresponding growth in load in the industrial sector and weather related growth in the residential sector.

Effective February 1, 2016, the GBPA approved GBPC’s General Rate Application applicable for the 2016 through 2018 period. Residential customers will see decreases up to 4.5 per cent, while commercial customers will see an increase of 1.5 per cent. Commercial customers consume approximately 70 per cent of GBPC’s production. Rates were approved based upon an 8.8 per cent return on rate base, reduced from the previous level of 10 per cent. This rate decision allows for customers to install renewable energy systems and sell their excess energy to GBPC. This is based on a tariff rider scheduled to be in place by Q3 2016.

Tropical Storm Erika affected the island of Dominica on August 27, 2015 and as a result, weaker economic growth is expected to affect sales into 2016. In connection with its pending rate case, Domlec made a preliminary filing in 2014 requesting that a weighted average cost of capital rate of 11.6 per cent be used for rate making purposes. In Q2 2015, the IRC set a cost of capital rate of 8.56 per cent, which Domlec unsuccessfully appealed to the IRC. Domlec made a further appeal to the Dominican court. The rate filing and rate case proceedings will begin after the cost of capital is determined. The cost of capital rate hearing has been delayed, with no new hearing date yet determined due to Tropical Storm Erika.

There are growth opportunities for Emera in the Caribbean market centered on creating and capturing opportunities for cleaner fuels and renewable energy generation. As part of this initiative, construction of a 10 MW solar facility began in Barbados in Q4 2015 and is scheduled for completion in the first half of 2016. In addition, an application to export natural gas to countries with no free trade agreement with the United States, specifically The Bahamas, was filed with the US Department of Energy and approval was received on October 20, 2015, granting long-term multi contract authorization for Emera to export natural gas, by vessel, in the amount of 8 million standard cubic feet per day (“mmscfd”). This complements the authorization received in April 2015 to export up to 25 mmscfd to countries which have a free trade agreement with the United States.

Overall, Emera Caribbean 2016 USD earnings are expected to be consistent with prior years.

# Pipelines

The timing of the income from Pipelines is predominately a result of capital lease accounting treatment which yields declining earnings over the life of the asset.

Pipelines 2016 earnings are expected to be consistent with prior years.

# Emera Energy

Emera Energy Services

Emera Energy Services, Emera Energy's trading and marketing business, is generally dependent on market conditions. In particular, volatility in electricity and natural gas markets, which can be influenced by weather, local supply constraints and other supply/demand factors, can provide higher levels of margin opportunity. The past three years have seen favourable market conditions in this regard within Emera Energy's key markets, with Q1 2014, in particular, experiencing unprecedented market volatility. This was a result of the combined impacts of cold weather, constraints in the supply or transportation of natural gas, and other market factors, and contributed to very strong adjusted earnings from trading and marketing, particularly in 2014. 2015 has seen lower market volatility and pricing, and a resulting decrease in trading and marketing adjusted earnings compared to 2014.

In addition to capitalizing on volatility-driven market opportunities, Emera Energy Services expects to continue to grow organically building market share through superior customer service and expanding its geographic reach to adjacent markets, including the Marcellus Shale region.

Planned investment by the industry in gas transportation infrastructure within the Northeast over the next few years could reduce the degree of volatility recently experienced in the market, all other things being equal. This could negatively affect profitability during certain periods.

Emera Energy Generation

Earnings from Emera Energy Generation's assets are largely dependent on market conditions, in particular, the relative pricing of electricity and natural gas and capacity pricing for the New England Gas Generation Facilities. Efficient operations of the fleet to ensure unit availability, cost management and effective commercial performance are key success factors.

2016 adjusted earnings from Emera Energy generating assets are expected to be lower than 2015, reflecting lower hedged and expected margins as compared to 2015.

In addition to energy margins and ancillary revenue, the New England Gas Generating Facilities and Bear Swamp earn revenue from capacity payments through the forward capacity market ("FCM"), the annual reconfiguration capacity market and the monthly reconfiguration capacity market. Prices for the FCM, the larger of the two components, are determined through an auction process held annually, three years in advance, providing revenue visibility to 2019, presuming the facilities continue to be available to support their capacity obligations. Details of pricing and estimated revenues are outlined in the table below for the New England Gas Generating facilities, and Emera Energy's 50 per cent interest in Bear Swamp.

| Forward Capacity Auction ("FCA") Year | Clearing Price in $/kW-month (in USD) | Approximate Estimated Annual Capacity Revenue (in USD) (1) |
|---|---|---|
| FCA6 (June 2015 to May 2016) | $3.43 | $40 million |
| FCA7 (June 2016 to May 2017) | $3.15 | $40 million |
| FCA8 (June 2017 to May 2018) | $7.025 | $100 million |
| FCA9 (June 2018 to May 2019) | $9.55 and $11.08 (2) | $145 million |
| FCA 10 (June 2019 to May 2020) | $7.03 | $106 million |

(1) Includes Emera's 50 per cent share of Bear Swamp's capacity revenue
(2) $11.08 was awarded for the Southeast Massachusetts/Rhode Island zone only and, as such, applies only to Tiverton

Bear Swamp's adjusted earnings will be lower in 2016 and the first half of 2017 primarily due to higher interest costs as a result of its Q4 2015 refinancing. Beginning Q3 2017, these interest costs will be offset by higher capacity revenues.

# Corporate and Other

Corporate and Other is dependent, in part, on business development and acquisition related initiatives, which in 2016 will include further acquisition costs related to the pending TECO Energy acquisition, equity investments in the Maritime Link Project and the Labrador-Island Link, project based construction services activity by Emera Utility Services, growth or fluctuations in APUC earnings (which Emera accounts one quarter after APUC reports such earnings), corporate financing and other corporate activities.

Corporate's contribution to consolidated net income in 2016 is expected to be lower than 2015 primarily due to further acquisition costs and associated financing initiatives related to the pending TECO Energy acquisition. These costs will include a non-cash accounting charge for the difference between Emera's closing share price on the issuance date of the convertible debentures and their exercise price. This will be recognized once the contingencies surrounding regulatory and other approvals are resolved.

On February 9, 2016, APUC announced its intention to acquire The Empire District Electric Company in a $3.4 billion transaction, which is expected to close in Q1 2017. The closing of this transaction and its related financing will reduce Emera's ownership interest.

**ENL**

*NSP Maritime Link Inc. ("NSPML")*

Through its subsidiary, NSP Maritime Link Inc., ENL has in total invested approximately $693.9 million of equity and debt, including $78.1 million of AFUDC, in the development of the Maritime Link Project. Project to date, ENL has invested a total of $154.9 million in equity, with the remaining costs being funded with working capital and debt, which has been guaranteed by the Government of Canada. AFUDC on invested equity is being capitalized at an annual rate of 9 per cent.

ENL's future earnings contribution from the Maritime Link Project will be affected by the timing of capital expenditures for design and construction activities, which will determine the component of costs to be funded by equity. Proceeds from the federally guaranteed debt financing completed in April 2014 were used to fund project costs until the Project's debt to equity ratio reached 70 per cent to 30 per cent respectively, which occurred in Q4 2015. From that point forward, project costs are funded with debt and equity at a 70 per cent to 30 per cent ratio, with equity contributions of $13.4 million in Q4 2015.

Maritime Link Project forecasted equity contributions for 2016 and 2017 are $157 million and $159 million respectively, with total equity for the Project estimated to be $470.9 million.

*Labrador Island Link ("LIL")*

ENL is a partner with Nalcor Energy in LIL, which is currently estimated at approximately $3.1 billion. As at December 31, 2015, ENL has invested $207.3 million of equity, including $21.2 million of equity earnings in LIL. Project to date, ENL has invested a total of $186.1 million in equity. Equity earnings are recorded based on an annual rate of 8.8 per cent of the equity invested. The return on ROE is approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("NLPUB"). There is currently an application being heard by the NLPUB which includes a review of ROE. The NLPUB's decision on ROE, expected in Q2 2016, will be applicable for all regulated electrical utilities in Newfoundland and Labrador and become the ROE applicable to ENL's investment in LIL.
ENL has an ongoing equity investment opportunity in LIL. Future earnings are dependent on the timing of additional equity investments and the approved ROE. Total equity contributions for 2015 for LIL are $118.4 million.

LIL forecasted equity contributions for 2016 are $223 million, with total equity investment, by Emera, in the Project estimated to be $409.1 million.

Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's consolidated balance sheets.

# TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Inter-company balances and inter-company transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues, with an offset to property, plant and equipment, regulated fuel for generation and purchased power, or operating, maintenance and general, depending on the nature of the transaction. 2014 balances have been retrospectively restated, consistent with this approach. Below are transactions between Emera and its associated companies reported in the Consolidated Statements of Income:

| For the<br>millions of Canadian dollars | | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | | | **2015** | 2014 |
| | **Nature of Service** | **Presentation** | | |
| **Sales to:** | | | | |
| APUC subsidiary | Net sale of natural gas and transportation | Operating revenue – non-regulated | **$ 3.0** | $ 4.4 |
| NWP | Energy management services | Operating revenue – regulated | **0.3** | 1.1 |
| **Purchases from:** | | | | |
| M&NP | Natural gas transportation capacity | Regulated fuel for generation and purchased power | **4.5** | 3.6 |
| M&NP | Natural gas transportation capacity | Operating revenue – non-regulated | **(23.4)** | (23.8) |
| NWP | Purchase of power | Regulated fuel for generation and purchased power | **$ 0.3** | $ 1.9 |

Operating revenue – non-regulated includes intercompany profit relating to the sale of natural gas, sale of power, construction, operations management and engineering services, and hedging services to rate-regulated subsidiaries of Emera totaling $1.6 million for the year ended December 31, 2015 (2014 – $4.2 million).

Amounts reported on Emera's Consolidated Balance Sheets due (to) from its equity investments are summarized in the following table:

| As at<br>millions of Canadian dollars | | December 31<br>2015 | | December 31<br>2014 |
|---|---|---|---|---|
| **Due from related parties:** | | | | |
| Subsidiary of APUC – current (1) | **$** | **0.7** | $ | - |
| NSPML – current | | **1.6** | | 3.5 |
| M&NP – loan receivable – long-term | | **2.5** | | 2.5 |
| **Due to related parties:** | | | | |
| M&NP – current | | **(2.1)** | | (1.6) |
| **Net due from (to) related parties** | **$** | **2.7** | $ | **4.4** |

(1) Amount due from a subsidiary of APUC is included in accounts receivable.

All amounts are under normal interest and credit terms, except for a loan receivable from M&NP bearing interest at 1 per cent per annum maturing on November 30, 2019.

# DIVIDENDS AND PAYOUT RATIOS

Emera Incorporated's common share dividends paid in 2015 were $1.66 ($0.3875 in Q1, $0.4000 in Q2 and Q3 and $0.4750 in Q4) and $1.48 ($0.3625 per quarter in Q1, Q2 and Q3 and $0.3875 in Q4) per common share for 2014, representing a payout ratio of 72.8 per cent of adjusted net income in 2015 and 65.8 per cent for 2014. The increase in the payout ratio is primarily due to an increase in dividends paid greater than growth in adjusted net income.

On August 10, 2015, Emera's Board of Directors approved an increase in the annual common share dividend rate from $1.60 to $1.90 per common share.

# ENTERPRISE RISK AND RISK MANAGEMENT

Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach to risk management. Certain risk management activities for Emera are overseen by the Enterprise Risk Management Committee to ensure such risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through approved policies.

The Company's risk management activities are focused on those areas that most significantly impact profitability, quality of income and cash flow. These risks include, but are not limited to, exposure to regulatory and political risk, acquisition, weather, changes in environmental legislation, energy consumption, foreign exchange, capital market and liquidity risk, interest rate, project development and construction risk, cybersecurity, non-regulated plant operational risk, credit, country, commercial relationships, commodity price risk, future employee benefit plan performance and funding, labour, information technology and un-insured risk.

In this section, Emera describes some of the principal risks that management believes could materially affect its business, revenues, operating income, net income, net assets, or liquidity or capital resources. The nature of risk is such that no list is comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

## Regulatory and Political Risk

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments in a timely manner. As cost-of-service utilities with an obligation to serve customers, NSPI, Emera Maine, BLPC, GBPC, and Domlec must obtain regulatory approval to change electricity rates and/or riders from their respective regulators. Costs and investments can be recovered upon approval by the respective regulator of the recovery in adjustments to rates and/or riders, which normally requires a public hearing process or may be mandated by other governmental bodies. In addition, the commercial and regulatory frameworks under which Emera and its subsidiaries operate can be impacted by significant shifts in government policy and changes in governments. Emera's investments in entities in which it has significant influence and which are subject to regulatory risk include: NSPML, APUC, M&NP, LIL and Lucelec.

During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these subsidiaries and their respective regulators determine whether to allow recovery and to adjust rates based upon the subsidiaries' evidence and any contrary evidence from other parties. In some circumstances, other government bodies may influence the setting of rates. The subsidiaries manage this regulatory risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, fuel-related audits, rate filings and capital plans. The subsidiaries employ a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

Brunswick Pipeline entered into a 25-year firm service agreement, expiring in 2034, with Repsol Energy Canada ("REC"), which was filed with the NEB. The firm service agreement provides for predetermined toll increases after the fifth and fifteenth year of the contract. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the NEB on a complaint basis. Brunswick Pipeline is required to make copies of tariffs and supporting financial information readily available to interested persons. Persons who cannot resolve traffic, toll and tariff issues with Brunswick Pipeline may file a complaint with the NEB. In the absence of a complaint, the NEB does not normally undertake a detailed examination of Brunswick Pipeline's tolls.

## Acquisition Risk

The risks associated with Emera's acquisition strategy include potential difficulties inherent in acquisitions that may adversely affect the results of an acquisition and these include delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies from completed transactions.

Emera mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

Completion of the Acquisition of TECO Energy

The closing of the acquisition of TECO Energy is subject to the commercial risks associated with a publicly owned regulated utility acquisition per the terms negotiated in the acquisition agreement. The acquisition is subject to approval of certain regulatory and government approvals, including approval by the New Mexico Public Regulation Commission, the Committee on Foreign Investment in the United States, and the satisfaction of closing conditions. Shareholder approval of the transaction was received on December 3, 2015. On December 14, 2015, the New Mexico Public Regulation Commission established a hearing to begin on May 23, 2016 for the joint application for approval of the change in control of New Mexico Gas Co. effected by the Transaction. On January 21, 2016, the FERC approved the Transaction. On February 8, 2016, the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, waiting period expired.

Failure to obtain the required approvals or satisfy or waive the conditions contained in the acquisition agreement may result in the termination of the acquisition agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Emera will complete the acquisition in the timeframe or on the basis described herein, if at all. The termination of the acquisition agreement may have a negative effect on the price of the instalment receipts, the Debentures and the common shares and will result in the redemption of the Debentures. If the closing of the acquisition does not take place as contemplated, the Company could suffer adverse consequences, including the loss of investor confidence.

A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Company's ability to complete the acquisition and on the Company's or TECO Energy's business, financial condition or results of operations. In addition, in the event that such regulatory agencies impose unfavourable terms and/or conditions on Emera or any TECO Energy utility (including the requirement to sell or divest of certain assets or limitations on the future conduct of the individual or combined entities), the Company would still be required to complete the transaction on the terms set forth in the acquisition agreement. Emera intends to complete the acquisition within three days of obtaining the required TECO Energy shareholder approval and regulatory approvals and satisfaction of the other required closing conditions.

Emera expects the pending acquisition of TECO Energy will provide benefits to the Company, including that the acquisition will be accretive to Emera's EPS by approximately five per cent in the first full year following its completion (2017), excluding acquisition related expenses, growing to more than 10 per cent by the third full year (2019), assuming a USD/CAD exchange rate consistent with that at the time of announcement. As well, approximately 95 per cent of the expected foreign exchange exposure to close the pending acquisition has been actually or effectively hedged. In addition, the availability of net operating loss carry-forwards and alternative minimum tax credits, if utilized, are expected to provide significant accretion to Emera's cash position. However, there is a risk that some or all of the expected benefits of the acquisition may fail to materialize, or may not occur within the time periods anticipated by the Company. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Company. The challenge of combining previously independent businesses makes evaluating the Company's business and future financial prospects difficult. The past financial performance of the Company may not be indicative of its future financial performance. In addition, any regulatory approvals required in connection with the acquisition may include terms which could have an adverse effect on the Company's financial performance, including reduced revenues or investment recovery, increased competition or costs, or adverse alterations to the rate structure.

Failure to realize the anticipated benefits of the acquisition may impact the financial performance of the Company, the price of its common shares and the ability of Emera to continue to pay dividends on its common shares at current levels or at all. The declaration of dividends by the Company is at the discretion of the Board of Directors.

In addition to the potential liability for damages for breach of the acquisition agreement by Emera, if (i) the acquisition agreement is terminated by either party due to a failure to obtain the required regulatory approvals by the end date specified in the acquisition agreement, or because there is a final and non-appealable legal restraint that relates to the required regulatory approvals, or if TECO Energy terminates the acquisition agreement based on a failure by Emera to perform its agreements with respect to the receipt of the required regulatory approvals, and, in each case, at the time of such termination the TECO Energy shareholder approval shall have been obtained and the other closing conditions on behalf of Emera shall have been satisfied or waived (except for those conditions, that by their nature, are to be satisfied at the closing of the acquisition, but which conditions would be satisfied, or would be capable of being satisfied, if the closing of the Acquisition were to occur on the date of such termination and those conditions that have not been satisfied as a result of a breach of the acquisition agreement by Emera), or (ii) TECO Energy terminates the acquisition agreement in the event that all applicable closing conditions have been satisfied or waived and Emera fails to close the acquisition because of a failure of any person or entity to provide acquisition financing, then Emera will be obligated to pay to TECO Energy a fee of $326.9 million USD in cash.

For the purpose of financing the pending acquisition, Emera completed a $2.185 billion Debenture Offering in September and October 2015, including the exercise of an over-allotment. The Company also obtained a commitment letter for an aggregate of $6.5 billion USD non-revolving credit facilities. On October 16, 2015, Emera permanently reduced the USD bridge facilities in the amount of $588.3 million USD with the proceeds of the first instalment of the convertible debentures and the proceeds from the Bear Swamp financing. The commitment of the lenders to enter into the acquisition credit facilities is subject to certain standard conditions, which may result in such facilities becoming unavailable to Emera in certain circumstances. If the acquisition credit facilities become unavailable to Emera, Emera may not be able to complete the acquisition.

Completion of the acquisition is not conditional on the completion of the Debenture Offering by the Company or on the Company obtaining financing on favourable terms or at all. If a material amount due on payment of the final instalment is not paid by holders of instalment receipts and the Company is not able to quickly realize on the Debentures pledged to secure the obligation to pay the final instalment, the Company will not be able to use those proceeds to repay the acquisition credit facilities. As a result, it may take Emera longer than anticipated to repay the acquisition credit facilities which may have a negative impact on the consolidated capitalization of Emera until such time as the acquisition credit facilities have been repaid by Emera in full.

There is no guarantee that alternate sources of funding will be available to Emera or its affiliates at the desired time or at all, or on cost-effective terms. The inability to obtain alternate sources of funding to fund the acquisition or replace the acquisition credit facilities may negatively impact the financial performance of Emera, including the extent to which the acquisition is accretive. In addition, any movement in interest rates that could affect the underlying cost of these instruments may affect the expected accretion of the acquisition.

Emera expects to incur a number of costs associated with completing the acquisition. The majority of these costs will be non-recurring expenses resulting from the acquisition and will consist of transaction costs related to the acquisition, including costs relating to the financing of the acquisition and obtaining regulatory approvals. Additional unanticipated costs may be incurred relating to the acquisition.

Between September 16, 2015 and November 2, 2015, purported shareholders of TECO Energy filed twelve separate complaints styled as class action lawsuits in the Circuit Court for the 13th Judicial Circuit, in and for Hillsborough County, Florida or the United States District Court for the Middle District of Florida (the “Merger Litigation”). Each complaint alleges, among other things, that the Board of Directors of TECO Energy breached its fiduciary duties in agreeing to the acquisition agreement and that Emera and/or Emera US Inc. aided and abetted such alleged breaches. The complaints seek to enjoin the merger pursuant to the acquisition agreement.

On November 17, 2015, TECO Energy, Emera, Emera US Inc. and the Board of Directors of TECO Energy entered into a memorandum of understanding with the shareholder plaintiffs to settle all of the Merger Litigation, subject to negotiation of a stipulation of settlement with the plaintiffs and to court approval. The memorandum of understanding provides for all claims against the defendants to be released in exchange for TECO Energy making certain additional disclosures to its shareholders related to the proposed merger (which have now been made).

There is no assurance that the parties will ultimately enter into a stipulation of settlement or that the court will approve the settlement even if the parties were to enter into a stipulation of settlement.

**Weather Risk**

Shifts in weather patterns affect electric sales volumes and associated revenues and costs. Extreme weather events generally result in increased operating costs associated with restoring power to customers, as a result of unplanned outages. Emera responds to significant weather events related outages according to each subsidiary’s respective emergency services restoration plan.

**Changes in Environmental Legislation**

Emera is subject to regulation by federal, provincial, state, regional and local authorities with regard to environmental matters; primarily related to its utility operations. This includes laws setting greenhouse gas ("GHG") emissions standards and air emissions standards. Emera is also subject to laws regarding the generation, storage, transportation, use and disposal of hazardous substances and materials.

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is, and may be, material to Emera. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on Emera.

New emission reductions requirements for the utilities sector are being established by governments in Canada and the United States. Changes to GHG emissions standards and air emissions standards could adversely affect Emera's operations and financial performance. Stricter environmental laws and enforcement of such laws in the future could increase Emera's exposure to additional liabilities and costs. These changes could also affect earnings and strategy by changing the nature and timing of capital investments.

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and with the objective of achieving full compliance with applicable laws, legislation and company policies and standards. Emera has implemented this policy through the development and application of environmental management systems in its operating subsidiaries. Comprehensive audit programs are also in place to regularly test compliance with such laws, policies and standards.

**Energy Consumption Risk**

Typical of utilities, Emera is affected by demand for energy in the areas in which it operates based upon fluctuations in general economic conditions, such as changes in employment levels, personal disposable income, energy prices and housing starts. Customers' focus on energy efficiency could also result in changes in energy consumption.

Government policies promoting distributed generation ("DG") and new technology developments enabling those policies, particularly with rooftop solar, have the potential to impact residential sales and thereby revenues. This could negatively impact operations, net earnings and cash flows. Energy costs and clean energy options have increased demand for products enabling the consumers' ability to self-generate.

**Foreign Exchange Risk**

The Company is exposed to foreign currency exchange rate changes. In 2015, approximately 50 per cent of Emera's adjusted net income was derived from subsidiaries with US functional currency. As such, its earnings are subject to fluctuations in the Canadian dollar to US dollar exchange rate. As discussed below, the pending acquisition of TECO Energy will increase this percentage significantly.

The Company identifies and hedges significant transactional currency risks in accordance with its policies and procedures. Emera does not currently hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries are included in accumulated other comprehensive income (loss) ("AOCI").

The Company enters into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams, capital expenditures and capital projects. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including foreign exchange.

Emera does not enter into hedges for its foreign currency translation exposure on its non-Canadian assets. Any changes in the Canadian exchange rate will affect the equivalent Canadian dollar value of such assets, and the equivalent Canadian dollar value of these assets, revenues and earnings contributions.

Pending TECO Energy Acquisition

The cash consideration for the acquisition is required to be paid in US dollars, while funds raised in the Debenture Offering or any other Canadian dollar offering, which may constitute a significant portion of the funds ultimately used to finance the acquisition, are denominated in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar prior to either the payment of the final instalment or the close of any Canadian dollar offerings will increase the purchase price translated in Canadian dollars and thereby increase the Canadian dollars required to fund the US dollar purchase price for the acquisition ultimately obtained by Emera.

The proceeds of the first instalment of the Debenture Offering and the overallotment were converted to US dollars and invested in short-term US dollar investment grade securities. During the month of October 2015, Emera entered into foreign exchange forward contracts to economically hedge an amount equal to the anticipated proceeds from the second instalment of the Debenture Offering of the pending TECO Energy acquisition of $1.457 billion. These foreign exchange contracts are economic hedges and do not qualify for hedge accounting. Therefore, all mark-to-market gains and losses related to the forwards and related to the US denominated cash proceeds will be recognized in net income for the period. Until the hedge settles and the USD denominated cash is used to acquire TECO Energy, foreign exchange fluctuations could create significant mark-to-market adjustments that may result in volatility in Emera's earnings.

In addition, the operations of TECO Energy are conducted in US dollars. Following the acquisition, the consolidated net income and cash flows of Emera will be impacted to a greater extent by movements in the US dollar relative to the Canadian dollar. In particular, decreases in the value of the US dollar versus the Canadian dollar following the acquisition, could negatively impact the Company's net income as reported in Canadian dollars, which could cause a failure to realize all or some of the anticipated benefits of the acquisition, including accretion.

**Capital Market and Liquidity Risk**

Emera's utility and non-utility operations and projects in development require significant capital investments in property, plant and equipment. Consequently, Emera is an active participant in the debt and equity markets. Any disruption in capital markets could have a material impact on Emera's ability to fund its operations. Capital markets are global in nature and are affected by numerous events throughout the world economy. Capital market disruptions could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions.

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera forecasts cash requirements on a continuous basis to determine whether sufficient funds are available. Liquidity and capital needs will be financed through internally generated cash flows, short-term credit facilities, and ongoing access to capital markets. The Company reasonably expects liquidity sources to exceed ordinary course capital needs.

Emera is subject to financial risk associated with changes in its credit ratings. A change to a credit rating could result in higher interest rates in future financings, increase borrowing costs under certain existing credit facilities, limit access to the commercial paper market or limit the availability of adequate credit support for subsidiary operations.

**Interest Rate Risk**

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk. Emera seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

The Company is subject to interest rate risk relating to certain sources of expected funds to effect the TECO Energy acquisition. Any movement in interest rates could affect the underlying cost of the instrument used to fund the acquisition. The Company may enter into interest rate hedging contracts to limit its exposure to fluctuations in interest rates.

For Emera's regulated subsidiaries, the cost of debt is generally passed through to ratepayers. While regulatory ROE rates will generally and indirectly follow the direction of interest rates, such that regulatory ROE's are likely to fall in times of reducing interest rates and raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

**Project Development and Construction Risk**

ENL's planned investment in the development of the Maritime Link Project has risks commensurate with any large construction project. Risks related to such large projects include impact on costs of schedule delays and risk of cost overruns. Emera has deployed a robust project and risk management approach to this project, led by a team with extensive experience in large projects. There are also significant contractual terms in place protecting Emera and ENL from any exposure to cost overruns to either of Nalcor's projects and with specific provisions for Nalcor sharing in cost overruns of the Maritime Link Project.

In February 2015, ENL entered into a contract with Abengoa S.A., a global Spanish energy company, for the transmission line construction on the Maritime Link Project. On November 25, 2015, Abengoa S.A. filed a notice under Spanish law, which provides for pre insolvency protection in Spain, giving the company up to four months to reach an agreement with creditors to avoid a full insolvency process. ENL is working closely with Abengoa and the performance bond sureties to minimize project impacts. Work on the Project continues.

**Cybersecurity Risk**

Emera's reliance on information technology to manage its business exposes the Company to potential risks related to cybersecurity attacks and unauthorized access to the Company's, customers', suppliers', counterparties' and employees' sensitive or confidential information, (which may include personally identifiable information and credit information) through hacking, viruses and otherwise (collectively "cybersecurity threats"). The Company uses information technology systems and network infrastructure, which include controls for interconnected systems of generation, distribution, and transmission, some of which is shared with third parties for operating purposes. Through the normal course of business, the Company also collects, processes, and retains sensitive and confidential customer, supplier, counter-party and employee information.

Despite security measures in place, the Company's systems, assets and information could be vulnerable to cybersecurity attacks and other data security breaches that could cause system failures, disrupt operations, adversely affect safety, result in loss of service to customers and release of sensitive or confidential information. Should such cybersecurity threats materialize the Company could suffer costs, losses and damages; all or some of which may not be recoverable through regulatory processes or otherwise.

## Emera Energy Trading and Marketing

The majority of Emera's portfolio of electricity and gas marketing and trading contracts, and in particular its natural gas asset management arrangements, are contracted on a back-to-back basis, avoiding any material long or short commodity positions. However, the portfolio is subject to commodity price risk, particularly with respect to basis point differentials between relevant markets, in the event of an operational issue or counterparty default. To measure commodity price risk exposure, Emera employs a number of controls and process, including an estimated value-at-risk ("VaR") analysis of its exposures. The VaR amount represents an estimate of the potential change in fair value that could occur from changes in market factors within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with physical commodity, primarily in natural gas and power positions. The Company's commercial arrangements, including the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements and financial hedging instruments, as well as its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are all used to manage and mitigate this risk.

## Emera Energy Electricity Sales and Non-Regulated Fuel for Generation and Purchased Power

Emera Energy's natural gas fired plants in northeastern United States, operating as merchant facilities, are susceptible to the volatility of the New England electricity market and natural gas prices. Market electricity prices are dependent upon a number of factors, including the projected supply and demand of electricity, natural gas prices, the price of other materials used to generate electricity, the cost of complying with applicable environmental and other regulatory requirements and weather conditions. A material change in any one of these factors can materially affect the profitability of the facilities.

## Non-Regulated Plant Operational Risk

Emera owns three combined-cycle gas-fired electricity generating facilities in New England (New England Gas Generating Facilities) as well as a gas fired generating facility and biomass fired generating facility in Maritime Canada (Bayside Power and Brooklyn Energy). Power plant operations involve the risk of outages due to failure of generation equipment, transmission lines, pipelines or other equipment, which could make the affected plant unavailable to provide service. Unplanned outages could result in lost revenues, increased capital costs and maintenance expenses, payment of cover costs for any hedges in place, and reduced profitability. Insurance is maintained to mitigate operating risks.

## Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits and derivative assets. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties, and deposits or collateral are requested on any high risk accounts.

## Country Risk

Operating revenues outside of Canada constituted 45 per cent (28 per cent from the US and 17 per cent from the Caribbean) of Emera's total operating revenues in 2015 (2014 – 48 per cent, with 31 per cent from the US and 17 per cent from the Caribbean). Emera's investments are currently in regions where the political and economic risk levels are considered by the Company to be acceptable. Emera's operations in some countries may be subject to the following risks: changes in the rate of economic growth, restrictions on the repatriation of income or capital exchange controls, inflation, the effect of global health, safety and environmental matters or economic conditions and market conditions, and change in financial policy and availability of credit.

**Commercial Relationships Risk**

The Company is exposed to commercial relationships risk in respect of its reliance on certain key partners, suppliers and customers. The Company manages its commercial relationships risk by monitoring credit risk, as discussed below in Credit Risk, and monitoring of significant developments with its customers, partners and suppliers.

**Commodity Price Risk**

A large portion of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. Fuel contracts may be exposed to broader global conditions, which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable. In addition, the adoption and implementation of fuel adjustment mechanisms in its rate-regulated subsidiaries has further helped manage this risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

**Future Employee Benefit Plan Performance and Funding Risk**

Certain Emera subsidiaries have both defined benefit and defined contribution employee benefit plans that cover their employees and retirees. All defined benefit plans are closed to new entrants. The cost of providing these benefit plans varies depending on the plan provisions, interest rates, investment performance and actuarial assumptions concerning the future. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels and contributions to the plans) and expectations around future salary growth, inflation and mortality. Two of the largest drivers of cost are investment performance and interest rates, which are affected by global financial and capital markets. Depending on future interest rates and actual versus expected investment performance, Emera could be required to make larger contributions in the future to fund these plans, which could affect Emera's cash flows, financial condition and operations.

**Labour Risk**

Certain Emera employees are subject to collective labour agreements. Approximately 49 per cent of the full-time and term employees within the Emera labour force are represented by local unions.

As at December 31, 2015, approximately seven per cent of the entire labour force is covered by collective labour agreements that will expire within the next 12 months. Emera seeks to manage this risk through ongoing discussions with local unions. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labor disruption.

**Information Technology Risk**

Emera relies on various information technology systems to manage operations. This subjects Emera to inherent costs and risks associated with maintaining, upgrading, replacing and changing these systems. This includes impairment of its information technology, potential disruption of internal control systems, substantial capital expenditures, demands on management time and other risks of delays, difficulties in upgrading existing systems, transitioning to new systems or integrating new systems into its current systems.

### Uninsured Risk

Emera and its subsidiaries maintain insurance to cover accidental loss suffered to its facilities, and to provide indemnity in the event of liability to third parties. This is consistent with Emera's risk management policies. There are certain elements of Emera's operations which are not insured. These include a significant portion of its electric utilities' transmission and distribution assets, as is customary in the industry. The cost of this coverage is not economically viable. In addition, Emera accepts deductibles and self-insured retentions under its various insurance policies. Insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities or losses that may be incurred by the Company and its subsidiaries will be covered by insurance. Emera's regulated utilities would likely apply to their respective regulatory authority to recover any loss or liability through increased customer rates, though there is no assurance the regulatory authority would approve such application in whole or in part.

The occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by Emera and its subsidiaries or claims that fall within a significant self-insured retention could have a material adverse effect on Emera's results of operations, cash flows and financial position, if regulatory recovery is not available. A limited portion of Emera's property and casualty insurance is placed with a wholly owned captive insurance company. If a loss is suffered by the captive insurer, it is not able to recover that loss other than through future premiums.

# RISK MANAGEMENT INCLUDING FINANCIAL INSTRUMENTS

Emera's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are overseen by the Board of Directors. The Company has established a number of processes and practices to identify, monitor, report on and mitigate material risks to the Company. This includes establishment of the Enterprise Risk Management Committee, whose responsibilities include preparing and updating a "Risk Dashboard" for the Board of Directors on a quarterly basis. Furthermore, a corporate team independent from operations is responsible for tracking and reporting on market and credit risks.

The Company manages its exposure to normal operating and market risks relating to commodity prices, foreign exchange and interest rates through contractual protections with counterparties where practicable, as well as by using financial instruments consisting mainly of foreign exchange forwards and swaps, interest rate options and swaps, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. Collectively, these contracts and financial instruments are considered "derivatives".

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty creditworthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and can be proven to effectively hedge the identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized. Any ineffective portion of the change in the fair value of the cash flow hedges is recognized in net income in the reporting period.

Where the documentation or effectiveness requirements are not met, the derivatives are recognized at fair value, with any changes in fair value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

Derivatives entered into by NSPI and GBPC that are documented as economic hedges, and for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The realized gain or loss is recognized when the hedged item settles in regulated fuel for generation and purchased power, inventory or property, plant and equipment, depending on the nature of the item being economically hedged. Management believes that any gains or losses resulting from settlement of these derivatives be refunded to or collected from customers in future rates.

Derivatives that do not meet any of the above criteria are designated as HFT and are recognized on the balance sheet at fair value. All gains or losses are recognized in net income of the period unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category when another accounting treatment applies.

**Hedging Items Recognized on the Balance Sheets**

The Company has the following categories on the balance sheet related to derivatives in valid hedging relationships:

| As at<br>millions of Canadian dollars | | **December 31<br>2015** | | December 31<br>2014 |
|---|---|---|---|---|
| Derivative instrument assets (current and other assets) | **$** | **19.8** | $ | 23.0 |
| Derivative instrument liabilities (current and long-term liabilities) | | **(46.2)** | | (19.2) |
| Net derivative instrument assets (liabilities) | **$** | **(26.4)** | $ | 3.8 |

**Hedging Impact Recognized in Net Income**

The Company recognized gains (losses) related to the effective portion of hedging relationships under the following categories:

| For the<br>millions of Canadian dollars | | | | Year ended<br>December 31 |
|---|---|---|---|---|
| | | **2015** | | 2014 |
| Operating revenues – regulated | **$** | **(9.0)** | $ | (3.7) |
| Non-regulated fuel for generation and purchased power | | **4.8** | | 0.9 |
| Income from equity investments | | **(0.6)** | | (0.5) |
| Interest expense, net | | **-** | | (0.2) |
| Effective net gains (losses) | **$** | **(4.8)** | $ | (3.5) |

The effective net gains (losses) reflected in the above table would be offset in net income by the hedged item realized in the period.

The Company recognized in net income the following gains (losses) related to the ineffective portion of hedging relationships under the following categories:

| For the<br>millions of Canadian dollars | | | | Year ended<br>December 31 |
|---|---|---|---|---|
| | | **2015** | | 2014 |
| Non-regulated fuel for generation and purchased power | **$** | **(0.1)** | $ | 2.7 |
| Ineffective gains (losses) | **$** | **(0.1)** | $ | 2.7 |

### Regulatory Items Recognized on the Balance Sheets

The Company has the following categories on the balance sheet related to derivatives receiving regulatory deferral:

| As at<br>millions of Canadian dollars | | **December 31<br>2015** | | December 31<br>2014 |
|---|---|---|---|---|
| Derivative instrument assets (current and other assets) | **$** | **209.9** | $ | 97.7 |
| Regulatory assets (current and other assets) | | **64.3** | | 43.6 |
| Derivative instrument liabilities (current and long-term liabilities) | | **(64.3)** | | (40.3) |
| Regulatory liabilities (current and long-term liabilities) | | **(209.9)** | | (97.7) |
| Net asset (liability) | **$** | **-** | $ | 3.3 |

### Regulatory Impact Recognized in Net Income

The Company recognized the following net gains (losses) related to derivatives receiving regulatory deferral as follows:

| For the<br>millions of Canadian dollars | | **2015** | | Year ended December 31<br>2014 |
|---|---|---|---|---|
| Regulated fuel for generation and purchased power (1) | **$** | **41.2** | $ | 17.7 |
| Net gains (losses) | **$** | **41.2** | $ | 17.7 |

(1) Realized gains (losses) on derivative instruments settled and consumed in the period, hedging relationships that have been terminated or the hedged transaction is no longer probable. Realized gains (losses) recorded in inventory will be recognized in "Regulated fuel for generation and purchased power" when the hedged item is consumed.

### Held-for-trading Items Recognized on the Balance Sheets

The Company has the following categories on the balance sheet related to HFT derivatives:

| As at<br>millions of Canadian dollars | | **December 31<br>2015** | | December 31<br>2014 |
|---|---|---|---|---|
| Derivative instruments assets (current and other assets) | **$** | **95.3** | $ | 107.8 |
| Derivative instruments liabilities (current and long-term liabilities) | | **(331.9)** | | (145.3) |
| Net derivative instrument assets (liabilities) | **$** | **(236.6)** | $ | (37.5) |

### Held-for-trading Items Recognized in Net Income

The Company has recognized the following realized and unrealized gains (losses) with respect to HFT derivatives in net income:

| For the<br>millions of Canadian dollars | | | | Year ended<br>December 31 |
|---|---|---|---|---|
| | | **2015** | | 2014 |
| Non-regulated operating revenues | **$** | **14.4** | $ | 270.4 |
| Non-regulated fuel for generation and purchased power | | **(3.1)** | | (5.2) |
| Other income (expenses), net | | **(0.8)** | | - |
| Net gains (losses) | **$** | **10.5** | $ | 265.2 |

**Other Derivatives Recognized on the Balance Sheets**

The Company has the following categories on the balance sheet related to other derivatives:

| As at<br>millions of Canadian dollars | **December 31<br>2015** | December 31<br>2014 |
|---|---|---|
| Derivative instrument assets (current and other assets) | **$ 92.1** | $ - |
| Derivative instrument liabilities (current and long-term liabilities) | **$ (2.9)** | $ - |
| Net derivative instrument assets (liabilities) | **$ 89.2** | $ - |

**Other Derivatives Recognized in Net Income**

The Company recognized in net income the following gains (losses) related to other derivatives:

| For the<br>millions of Canadian dollars | | Year ended<br>December 31 |
|---|---|---|
| | **2015** | 2014 |
| Other income (expense) | **$ 92.1** | $ - |
| Interest expense, net | **(2.9)** | - |
| Total gains (losses) | **$ 89.2** | $ - |

# DISCLOSURE AND INTERNAL CONTROLS

The Company, under the supervision and participation of management, including the Chief Executive Officer and Chief Financial Officer, has designed as at December 31, 2015 disclosure controls and procedures (“DC&P”) and internal controls over financial reporting (“ICFR”) as those terms are defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”).

The Chief Executive Officer and the Chief Financial Officer have caused to be evaluated under their supervision, with the assistance of Company employees, the effectiveness of the Company’s DC&P and ICFR, and based on that evaluation, have concluded DC&P and ICFR were effective at December 31, 2015.

There have been no changes in Emera or its consolidated subsidiaries’ ICFR during the period beginning on January 1, 2015 and ending on December 31, 2015, which have materially affected or are reasonably likely to materially affect ICFR.

# CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company’s estimates on an ongoing basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill impairment assessments, income taxes, asset retirement obligations, capitalized overhead and valuation of derivative instruments. Actual results may differ significantly from these estimates.

## Rate Regulation

The rate-regulated accounting policies of NSPI, Emera Maine, BLPC, Domlec, GBPC, and Brunswick Pipeline may differ from accounting policies for non-rate-regulated companies. NSPI, Emera Maine, BLPC, Domlec, and GBPC's accounting policies are subject to examination and approval by their respective regulators. These accounting policy differences occur when the regulators render their decisions on rate applications or other matters, and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on the expectation of the future actions of the regulators.

Emera has recorded $699.5 million (2014 - $602.7 million) of regulatory assets and $370.6 million (2014 - $201.9 million) of regulatory liabilities as at December 31, 2015.

## Pension and Other Post-Retirement Employee Benefits

The Company provides post-retirement benefits to employees, including defined benefit pension plans. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The benefit cost and accrued benefit obligation for employee future benefits included in annual compensation expenses are affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings on plan assets.

Changes to the provision of the plan may also affect current and future pension costs. Benefit costs are also affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs.

The pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

Emera's accounting policy is to amortize the net actuarial gain or loss, which exceeds 10 per cent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period, which is currently nine years. Emera's use of smoothed asset values further reduces the volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

The discount rate used to determine benefit costs is based on the yield of high quality long-term corporate bonds in each operating entity's country. The discount rate is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year. NSPI rounds its discount rate to the nearest 25 basis points. Effective January 1, 2014, Bangor Hydro Electric Company and Maine Public Service Company merged to become Emera Maine. The pension plans related to the pre-merger companies have remained separate and are disclosed separately below. For benefit cost purposes, NSPI's rate was 4.00 per cent for 2015 (2014 – 5.00 per cent) and Bangor Hydro's rate was 3.91 per cent for 2015 (2014 – 4.83 per cent), MPS' rate was 3.77 for 2015 (2014 – 4.59 per cent) and GBPC's rate for 2015 was 4.75 per cent (2014 – 5.00 per cent).

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The benefit cost calculations assumed that plan assets would earn a rate of return of 5.75 per cent for 2015 (2014 – 6.25 per cent) for NSPI and 7.50 per cent for 2015 and 2014 for Bangor Hydro and MPS, and 6.00 per cent for both 2015 and 2014 for GBPC.

The reported benefit cost for defined benefit and defined contribution plans in 2015, based on management's best estimate assumptions, is $73.0 million. While there are numerous assumptions which are used to determine the benefit cost, the discount rate and asset return assumptions have an impact on the calculations.

The following shows the impact on 2015 benefit cost of a 25 basis point change (0.25 per cent) in the discount rate and asset return assumptions:

| | 0.25% Increase | | 0.25% Decrease | |
|---|---|---|---|---|
| millions of dollars | 2015 | 2014 | 2015 | 2014 |
| Discount rate assumption | $(5.4) | $(5.4) | $5.4 | $5.4 |
| Asset return assumption | $(2.7) | $(2.4) | $2.6 | $2.4 |

## Unbilled Revenue

Electric revenues are billed on a systematic basis over a one- or two-month period for NSPI and a one-month period for Emera Maine and GBPC. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and of related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates. EUS Bahamas and Emera Utility Services include an estimate of work completed under contracts but not yet billed at the end of each month. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. As at December 31, 2015, unbilled revenues amount to $144.2 million (2014 – $141.1 million) on a base of annual operating revenues of approximately $2,789.3 million (2014 – $2,938.6 million).

## Property, Plant and Equipment

Property, plant and equipment represents 51.5 per cent of total assets recognized on the Company's balance sheet. Included in "Property, plant and equipment" are the generation, transmission and distribution and other assets of the Company. Due to the magnitude of the Company's property, plant and equipment, changes in estimated depreciation rates can have a material impact on depreciation expense.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated property, plant and equipment are determined based on formal depreciation studies and require the appropriate regulatory approval. NSPI's last depreciation study was completed in 2010 and approved by the UARB on May 11, 2011. BLPC's last depreciation study was completed in 2013 and has been submitted for regulatory review. A response time has not been issued. GBPC's last depreciation study was completed in 2015 and was approved on January 25, 2016. Emera Maine's last depreciation study was completed in 2013 and was applied to transmission rates effective January 1, 2014 and distribution rates effective July 1, 2014.

Depreciation expense was $295.9 million for the year ended December 31, 2015 (2014 – $277.5 million).

## Goodwill Impairment Assessments

Goodwill represents the excess of the acquisition purchase price for Emera Maine and GBPC over the fair values assigned to individual assets acquired and liabilities assumed. Emera is required to perform an impairment assessment annually, or in the interim if an event occurs that indicates the fair value of Emera Maine or GBPC may be below its carrying value. Emera performs its annual impairment test as at October 1.

Goodwill arose on the acquisitions of GBPC and Emera Maine. At December 31, 2015, this goodwill had a total carrying amount of $264.1 million (December 31, 2014 – $221.5 million)

Emera's reporting units will first assess qualitative factors to determine whether it is more likely than not that the assets' fair value is less than the carrying amount, in which case it is necessary to perform the quantitative goodwill impairment test. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value.

Determining the fair market value of goodwill is susceptible to changes from period to period as assumptions about future cash flows are required.

Emera reviewed the carrying amount of goodwill and no material goodwill impairments existed for the year ended December 31, 2015 or 2014.

## Income Taxes

Income taxes are determined based on the expected tax treatment of transactions recorded in the consolidated financial statements. In determining income taxes, tax legislation is interpreted in a variety of jurisdictions, the likelihood that deferred tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of deferred tax assets and liabilities are made. Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals requires judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" threshold may be recognized or continue to be recognized. Unrecognized tax benefits are re-evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in the examinations of the Company's tax returns.

## Asset Retirement Obligations

An ARO is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company's credit-adjusted risk free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. Accretion expense is included as part of "Depreciation and amortization". Any accretion expense not yet approved by the regulator is deferred to a regulatory asset in "Property, plant and equipment" and included in the next depreciation study. Accordingly, changes to the ARO or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the Company.

Some transmission and distribution assets may have conditional AROs, which are required to be estimated and recorded as a liability. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at fair value when an amount can be determined.

The key assumptions used to determine the ARO are as follows:

| Asset | Credit-adjusted risk-free rate | | Estimated undiscounted future obligation (millions of dollars) | | Expected settlement date (number of years) | |
|---|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | **2015** | 2014 |
| Thermal | **5.1 – 5.3%** | 5.2 – 5.3% | **$142.8** | $142.8 | **17 – 28** | 18 – 29 |
| Hydro | **5.1 – 5.3%** | 5.1 – 5.3% | **127.6** | 127.6 | **16 – 46** | 17 – 47 |
| Wind | **5.1 – 5.2%** | 5.1 – 5.2% | **27.4** | 27.4 | **13 – 20** | 14 – 21 |
| Combustion turbines | **5.1 – 5.3%** | 5.1 – 5.3% | **8.3** | 8.3 | **1 – 30** | 2 – 31 |
| Transmission & distribution | **4.3 – 5.8%** | 4.1 – 5.8% | **21.5** | 16.5 | **1 – 10** | 1 – 11 |
| Pipeline | **3.80%** | 3.80% | **18.1** | 18.1 | **19.5** | 19.5 |
| | | | **$345.7** | $340.7 | | |

As at December 31, 2015, the AROs recorded on the balance sheet were $114.7 million (2014 – $106.2 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $320.2 million, which will be incurred between 2016 and 2061. The majority of these costs will be incurred between 2032 and 2047.

## Capitalized Overhead

As required by their respective regulators, NSPI, Emera Maine, GBPC, BLPC and Domlec capitalize overhead costs that are not directly attributable to specific utility assets, but to the overall capital expenditure program. The methodology for the calculation of capitalized overhead is approved by their respective regulator. For the year ended December 31, 2015, $71.6 million (2014 – $68.4 million) of overhead costs were capitalized to capital assets. Any change in the methodology for the calculation and allocation of overhead costs could have a material impact on the amounts recognized as expenses versus assets.

## Financial Instruments

Emera is required to determine the fair value of all derivatives except those which qualify for the normal purchase, normal sale exception. Fair value is the price that would be received for the sale of an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information, including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

### Level Determinations and Classifications

Emera uses the Level 1, 2 and 3 classifications in the fair value hierarchy. The fair value measurement of a financial instrument is included in only one of the three levels and is based on the lowest level input significant to the derivation of the fair value. Fair values are determined, directly or indirectly, using inputs that are unobservable for the asset or liability. In limited circumstances, Emera may enter into commodity transactions involving non-standard features where market observable data is not available, or contracts with terms that extend beyond five years.

# CHANGES IN ACCOUNTING POLICIES AND PRACTICES

**Business Combinations – Simplifying the Accounting for Measurement-Period Adjustments, Accounting Standard Update ("ASU") Number ("No.") 2015-16**
In September 2015, the Financial Accounting Standards Board ("FASB") issued ASU 2015-16, Business Combinations – *Simplifying the Accounting for Measurement-Period Adjustments*. The amendment applies to entities that have reported provisional amounts related to a business combination for which the accounting is incomplete by the end of the reporting period and have an adjustment to provisional amounts previously recognized during a later measurement period. Changes in provisional amounts recorded for acquired assets and liabilities are to be adjusted in the period the adjustment is known, with a corresponding adjustment booked to goodwill. The acquirer is no longer required to revise comparative information from prior years for the effect of changes in provisional amounts. The Company has adopted ASU 2015-16 effective Q3 2015, with no impact on the consolidated financial statements as a result of implementation of this standard.

**Income Taxes – Balance Sheet Classification of Deferred Taxes, ASU 2015-17**
In November 2015, the FASB issued ASU 2015-17*, Income Taxes – Balance Sheet Classification of Deferred Taxes,* which simplifies the presentation of deferred income taxes. The amendment requires that deferred tax assets and liabilities be classified as noncurrent on the Consolidated Balance Sheets, regardless of whether the deferred income taxes are expected to be recovered or settled within the next twelve months. ASU-2015-17 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. Early adoption is permitted for any interim or annual financial statements that have not yet been issued.

The Company has early adopted ASU 2015-17 effective December 31, 2015, and 2014 balances have been retrospectively restated. This change decreased the current deferred income tax asset and liability by $49.2 million and $4.1 million respectively on the Consolidated Balance Sheets as at December 31, 2015 (2014 – $27.9 million and $15.7 million respectively). As a result of the change the long-term deferred income tax asset increased by $15.2 million (2014 – $24.1 million) and the long-term deferred income tax liability decreased by $29.9 million (2014 – increased by $11.9 million) on the Consolidated Balance Sheets as at December 31, 2015.

This change also reclassified a $11.9 million current deferred income tax regulatory liability (2014 – $8.0 million) to the long-term deferred income tax regulatory asset on the Consolidated Balance Sheets as at December 31, 2015.

**Fair Value Measurement Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), ASU No. 2015-07**
In May 2015, the FASB issued ASU 2015-07 removing the requirement to categorize and disclose, within the fair value hierarchy, all investments for which fair value is measured using the net asset value per share as a practical expedient. The Company has early adopted ASU No. 2015-07 effective December 31, 2015 and 2014. The adoption of this update resulted in disclosure of all investments for which fair value is measured using the net asset value per share methodology being disclosed outside of the fair-value hierarchy. As at December 31, 2015, total investments measured using the net asset value per share were $672.4 million (December 31, 2014 - $635.7 million).

## Future Accounting Pronouncements

**Revenue from Contracts with Customers, ASU No. 2014-09**
In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers,* which creates a new, principle-based revenue recognition framework and a new topic in the Accounting Standards Codification ("ASC"), Topic 606. ASC 606 also changes the basis for determining when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific aspects of revenue recognition and expands revenue disclosures. On July 9, 2015, the FASB deferred the effective date by one year. This standard will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

**Income Statement – Extraordinary and Unusual Items, ASU No. 2015-01**
In January 2015, the FASB issued ASU 2015-01, *Income Statement – Extraordinary and Unusual Items,* which simplifies the income statement presentation requirements by eliminating the concept of extraordinary items. ASU No. 2015-01 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

**Consolidation, ASU No. 2015-02**
In February 2015, the FASB issued ASU 2015-02, *Consolidation,* which changes the analysis a reporting entity must perform to determine whether it should consolidate certain types of legal entities. All legal entities are subject to re-evaluation under the revised consolidation model. ASU No. 2015-02 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

**Interest – Imputation of Interest, No. ASU 2015-03**
In April 2015, the FASB issued ASU 2015-03, Interest – *Imputation of Interest*, which simplifies the presentation of debt issuance costs. The amendments require debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected by the amendments in the update. ASU No. 2015-03 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. The adoption of this update will result in the reclassification of debt issuance costs from "Other long-term assets" to "Long-term debt" and "Convertible debentures represented by instalment receipts" on the Company's consolidated balance sheets. As at December 31, 2015, debt issuance costs included in "Other long-term assets were $66.8 million (December 31, 2014 - $18.8 million).

In August 2015, the FASB issued ASU 2015-15, *Interest – Imputation of Interest – Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*, which clarifies that the guidance in ASU No. 2015-03 does not apply to line-of-credit arrangements. ASU No. 2015-15 permits an entity to defer and present debt issuance costs as an asset and subsequently amortize these costs ratably over the time of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. ASU No. 2015-15 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. As at December 31, 2015, debt issuance costs associated with line-of-credit arrangements included in "Other long-term assets" were $4.0 million (December 31, 2014 - $4.1 million) on the Company's Consolidated Balance Sheets.

**Compensation – Retirement Benefits, ASU No. 2015-04**
In April 2015, the FASB issued ASU 2015-04, *Compensation – Retirement Benefits,* which is part of FASB's initiative to reduce complexity in accounting standards. This standard provides certain practical expedients for defined benefit pension or other post-retirement benefit plan measurement dates. ASU No. 2015-04 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

**Intangibles – Goodwill and Other – Internal-Use Software, ASU No. 2015-05**
In April 2015, the FASB issued ASU 2015-05, *Intangibles* **–** *Goodwill and Other* **–** *Internal-Use Software,* which provides guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, then the customer should account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer should account for the arrangement as a service contract. The guidance will not change GAAP for a customer's accounting for service contracts. ASU No. 2015-05 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

**Technical Corrections and Improvements, ASU No. 2015-10**
In June 2015, the FASB issued ASU 2015-10, *Technical Corrections and Improvements*, covering a wide range of topics in the codification to correct unintended application of guidance, or make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice or create a significant administrative cost. ASU No. 2015-10 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

**Inventory – Simplifying the Measurement of Inventory, ASU No. 2015-11**
In July 2015, the FASB issued ASU 2015-11, Inventory – *Simplifying the Measurement of Inventory*. The amendments require an entity to measure inventory at the lower of cost or net realizable value, whereas previously, inventory was measured at the lower of cost or market. ASU No. 2015-11 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

**Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities, ASU No. 2016-01**
In January 2016, the FASB issued ASU 2016-01, Financial Instruments – *Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. ASU No. 2016-01 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

# SUMMARY OF QUARTERLY RESULTS

| For the quarter ended<br>millions of dollars (except per share amounts) | **Q4 2015** | Q3 2015 | Q2 2015 | Q1 2015 | Q4 2014 | Q3 2014 | Q2 2014 | Q1 2014 |
|---|---|---|---|---|---|---|---|---|
| Operating revenues | **$ 731.6** | $ 642.3 | $ 526.9 | $ 888.5 | $ 782.7 | $ 539.0 | $ 566.6 | $ 1,050.3 |
| Net income attributable to common shareholders | **192.1** | 35.0 | 10.0 | 160.1 | 151.2 | 28.2 | 24.5 | 202.8 |
| Adjusted net income attributable to common shareholders | **87.1** | 23.3 | 48.0 | 171.6 | 78.5 | 49.9 | 44.2 | 146.6 |
| Earnings per common share – basic | **1.31** | 0.24 | 0.07 | 1.10 | 1.05 | 0.20 | 0.17 | 1.43 |
| Earnings per common share – diluted | **1.30** | 0.24 | 0.07 | 1.09 | 1.02 | 0.20 | 0.17 | 1.40 |
| Adjusted earnings per common share – basic | **0.59** | 0.16 | 0.33 | 1.18 | 0.54 | 0.35 | 0.31 | 1.03 |

Quarterly operating revenues and net income attributable to common shareholders are affected by seasonality. The first quarter is generally the strongest because a significant portion of the Company's operations are located in northeast North America, where winter is the peak electricity season. As the energy industry is seasonal in nature for companies like Emera, seasonal and other weather patterns, as well as the number and severity of storms, can affect the demand for energy and the cost of service. Quarterly results could be affected by items outlined in the Significant Items section and mark-to-market adjustments.

# OPERATING STATISTICS
## FIVE-YEAR SUMMARY

| Year ended December 31 | **2015** | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| Electric energy sales (GWh) | | | | | |
| Residential | **5,740.5** | 5,615.7 | 5,623.6 | 5,372.2 | 5,458.9 |
| Commercial | **11,153.9** | 10,989.6 | 7,156.9 | 6,174.7 | 6,562.3 |
| Industrial | **2,984.1** | 2,970.8 | 3,067.4 | 2,678.7 | 3,988.5 |
| Other | **373.6** | 385.3 | 357.9 | 371.2 | 347.0 |
| Total electric energy sales | **20,252.1** | 19,961.4 | 16,205.8 | 14,596.8 | 16,356.7 |
| Sources of energy (GWh) | | | | | |
| Thermal – coal | **6,364.0** | 6,609.0 | 7,098.0 | 6,223.0 | 6,848.0 |
| – oil | **1,668.4** | 1,584.5 | 1,417.5 | 1,355.1 | 1,070.8 |
| – natural gas | **7,782.3** | 7,691.7 | 3,685.9 | 3,726.0 | 4,304.7 |
| Biomass | **272.3** | 319.8 | 167.0 | - | - |
| Hydro | **1,040.4** | 1,129.6 | 1,002.6 | 828.0 | 1,414.5 |
| Wind | **259.0** | 258.0 | 261.0 | 256.0 | 247.0 |
| Purchases | **4,142.3** | 3,693.1 | 3,528.0 | 3,210.2 | 3,518.3 |
| Total generation and purchases | **21,528.7** | 21,285.7 | 17,160.0 | 15,598.3 | 17,403.3 |
| Losses and internal use | **1,276.6** | 1,324.3 | 954.2 | 1,001.5 | 1,046.6 |
| Total electric energy sold | **20,252.1** | 19,961.4 | 16,205.8 | 14,596.8 | 16,356.7 |
| Electric customers | | | | | |
| Residential | **747,629** | 742,110 | 738,444 | 702,738 | 696,970 |
| Commercial | **85,480** | 82,076 | 83,612 | 79,613 | 79,817 |
| Industrial | **2,628** | 2,637 | 2,711 | 2,521 | 2,517 |
| Other | **9,432** | 10,421 | 10,510 | 20,230 | 10,446 |
| Total electric customers | **845,169** | 837,244 | 835,277 | 805,102 | 789,750 |
| Capacity | | | | | |
| Emera-owned generating nameplate capacity (MW) | | | | | |
| Coal fired | **1,243.0** | 1,243.0 | 1,243.0 | 1,243.0 | 1,243.0 |
| Dual fired | **350.0** | 350.0 | 350.0 | 350.0 | 350.0 |
| Gas turbines | **1,819.0** | 1,799.0 | 1,796.5 | 746.5 | 666.0 |
| Biomass | **90.0** | 90.0 | 90.0 | - | - |
| Hydroelectric | **402.0** | 401.6 | 401.6 | 395.0 | 395.0 |
| Wind turbines | **82.0** | 82.0 | 82.0 | 82.0 | 82.0 |
| Diesel | **241.2** | 241.2 | 244.6 | 231.5 | 173.0 |
| Steam | **40.0** | 40.0 | 40.0 | 40.0 | 47.0 |
| Independent power producers | **593.0** | 370.0 | 308.0 | 300.0 | 264.0 |
| | **4,860.2** | 4,616.8 | 4,555.7 | 3,388.0 | 3,220.0 |
| Total number of employees | **3,454** | 3,530 | 3,558 | 3,374 | 3,458 |
| km of transmission lines | **7,504** | 7,215 | 7,224 | 6,803 | 6,800 |
| km of distribution lines | **46,162** | 44,811 | 44,771 | 39,590 | 41,600 |

| **REGULATED ELECTRIC** | Customers | Employee count | Peak demand (MW) | Energy sales (Gwh) | Total assets (billions) | Rate base (billions) | Income (millions) | Allowable ROE 2015 | Allowable ROE 2014 |
|---|---|---|---|---|---|---|---|---|---|
| NSPI | 506,452 | 1,727 | 1,825 | 10,412 | 4.6 | 3.8 | $ 129.9 | 8.75-9.25% | 8.75-9.25% |
| Emera Maine | 157,891 | 412 | 388 | 2,020 | 1.6 | 0.9 | 45.1 | 10.3 % | 10.6 % |
| BLPC (1) | 126,190 | 330 | 149 | 915 | 0.5 | 0.4 | 29.7 | 10.0 % | 10.0 % |
| GBPC(1) | 19,104 | 205 | 61 | 335 | 0.4 | 0.3 | 17.8 | 10.0 % | 10.0 % |
| Domlec (1) | 35,525 | 238 | 17 | 95 | 0.1 | 0.1 | 7.4 | 15.0 % | 15.0 % |

(1) These subsidiaries use return on rate base, as opposed to ROE.

# FIVE-YEAR FINANCIAL SUMMARY

| For the year ended December 31 | 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| millions of Canadian dollars | | | | | |
| **Consolidated Statements of Income** | | | | | |
| Operating Revenues | **$ 2,789.3** | $ 2,938.6 | $ 2,230.2 | $ 2,058.6 | $ 2,064.4 |
| Operating expenses | | | | | |
| Regulated fuel for generation and purchased power | **814.5** | 844.3 | 868.4 | 810.5 | 866.4 |
| Regulated fuel and fixed cost adjustments | **41.6** | 46.6 | (40.8) | 10.0 | (8.5) |
| Non-regulated fuel for generation and purchased power | **335.7** | 401.1 | 89.8 | 44.5 | 73.9 |
| Non-regulated direct costs | **19.5** | 31.3 | 52.4 | 56.6 | 60.9 |
| Operating, maintenance and general | **666.8** | 560.8 | 505.0 | 462.9 | 453.3 |
| Provincial, state and municipal taxes | **63.6** | 58.2 | 50.5 | 49.4 | 49.2 |
| Depreciation and amortization | **339.9** | 329.0 | 297.8 | 278.2 | 251.7 |
| **Income from operations** | **507.7** | 667.3 | 407.1 | 346.5 | 317.5 |
| Income from equity investments and Other income (expenses), net | **249.7** | 78.9 | 63.7 | 53.8 | 77.4 |
| Interest expense, net | **212.6** | 179.8 | 172.2 | 167.1 | 159.4 |
| **Income before provision for income taxes** | **544.8** | 566.4 | 298.6 | 233.2 | 235.5 |
| Income tax expense (recovery) | **92.4** | 113.6 | 43.3 | (12.4) | (23.9) |
| **Net income** | **452.4** | 452.8 | 255.3 | 245.6 | 259.4 |
| Non-controlling interest in subsidiaries | **24.9** | 19.9 | 18.5 | 13.7 | 11.7 |
| **Net income of Emera Incorporated** | **427.5** | 432.9 | 236.8 | 231.9 | 247.7 |
| Preferred stock dividends | **30.3** | 26.2 | 19.3 | 11.1 | 6.6 |
| **Net income attributable to common shareholders** | **397.2** | 406.7 | 217.5 | 220.8 | 241.1 |
| After-tax mark-to-market gain (loss) | **67.2** | 87.5 | (41.9) | (9.7) | (3.0) |
| Adjusted net income attributable to common shareholders | **330.0** | 319.2 | 259.4 | 230.5 | 244.1 |
| Adjusted EBITDA | **1,031.2** | 946.5 | 829.5 | 693.2 | 649.8 |
| **Balance Sheets Information** | | | | | |
| Current assets (1) | **2,595.6** | 1,410.8 | 1,152.3 | 940.2 | 993.3 |
| Property, plant and equipment, net of accumulated depreciation | **6,188.0** | 5,610.2 | 5,327.7 | 4,491.1 | 4,294.4 |
| Other assets | | | | | |
| Income taxes receivable | **48.7** | 28.9 | 27.8 | - | - |
| Deferred income taxes (1) | **32.2** | 57.8 | 67.8 | 28.9 | 33.1 |
| Derivative instruments | **167.6** | 92.0 | 61.6 | 23.4 | 39.6 |
| Pension and post-retirement asset | **8.7** | 5.9 | 0.5 | 0.1 | 0.3 |
| Regulatory assets | **605.3** | 487.7 | 557.8 | 376.4 | 312.2 |
| Net investment in direct financing lease | **480.1** | 484.5 | 487.2 | 490.0 | 492.0 |
| Investments subject to significant influence (2) | **1,145.3** | 1,027.6 | 739.2 | 536.6 | 219.8 |
| Available-for-sale investments | **116.0** | 84.4 | 74.2 | 141.8 | 54.6 |
| Goodwill | **264.1** | 221.5 | 206.5 | 193.5 | 197.7 |
| Intangibles, net of accumulated amortization | **191.9** | 134.3 | 118.4 | 114.2 | 100.7 |
| Due from related parties | **2.5** | 2.5 | 2.5 | 151.7 | 2.8 |
| Other long-term assets | **166.3** | 205.3 | 53.3 | 48.5 | 183.1 |
| **Total assets** | **12,012.3** | 9,853.4 | 8,876.8 | 7,536.4 | 6,923.6 |

# FIVE-YEAR FINANCIAL SUMMARY (continued)

| For the year ended December 31<br>millions of Canadian dollars | **2015** | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| Current liabilities | **2,081.3** | 1,122.9 | 1,529.9 | 951.9 | 801.7 |
| Long-term liabilities | | | | | |
| Long-term debt | **3,750.8** | 3,660.3 | 3,363.7 | 3,257.4 | 3,273.5 |
| Deferred income taxes (1) | **761.7** | 613.3 | 547.7 | 312.1 | 228.6 |
| Derivative instruments | **96.1** | 77.4 | 27.0 | 22.4 | 38.7 |
| Regulatory liabilities | **271.7** | 158.9 | 119.5 | 92.5 | 107.1 |
| Asset retirement obligations | **114.7** | 106.2 | 98.6 | 95.0 | 99.9 |
| Pension and post-retirement liabilities | **303.4** | 360.7 | 256.4 | 506.4 | 530.8 |
| Other long-term liabilities (2) | **298.5** | 48.3 | 36.8 | 20.9 | 19.6 |
| Equity | | | | | |
| Common stock | **2,157.5** | 2,016.4 | 1,703.0 | 1,643.7 | 1,385.0 |
| Cumulative preferred stock | **709.5** | 709.5 | 514.0 | 391.6 | 146.7 |
| Contributed surplus | **28.8** | 8.8 | 4.1 | 2.8 | 3.3 |
| Accumulated other comprehensive income (loss) | **136.5** | (347.6) | (430.1) | (775.8) | (671.7) |
| Retained earnings | **1,167.8** | 1,011.7 | 817.2 | 788.1 | 735.9 |
| Total Emera Incorporated equity | **4,200.1** | 3,398.8 | 2,608.2 | 2,050.4 | 1,599.2 |
| Non-controlling interest in subsidiaries | **134.0** | 306.6 | 289.0 | 227.4 | 224.5 |
| Total equity | **4,334.1** | 3,705.4 | 2,897.2 | 2,277.8 | 1,823.7 |
| **Total liabilities and equity** | **12,012.3** | 9,853.4 | 8,876.8 | 7,536.4 | 6,923.6 |
| **Statements of Cash Flow Information** | | | | | |
| Cash provided by operating activities | **674.2** | 762.5 | 564.2 | 397.6 | 399.5 |
| Cash used in investing activities | **(123.7)** | (710.9) | (921.6) | (919.4) | (660.8) |
| Cash provided by (used in) financing activities | **221.1** | 58.2 | 362.1 | 534.2 | 331.4 |
| **Financial ratios ($ per share)** | | | | | |
| Earnings per share | **$ 2.72** | $ 2.84 | $ 1.64 | $ 1.77 | $ 1.99 |
| Adjusted earnings per share | **$ 2.26** | $ 2.23 | $ 1.96 | $ 1.85 | $ 2.02 |

(1) Emera early adopted ASU 2015-17 *Income Taxes – Balance Sheet Classification of Deferred Taxes,* which simplifies the presentation of deferred income taxes effective Q4 2015. The December 31, 2014 and 2015 periods have been restated
(2) As at December 31, 2015 and 2014, the negative investment balance for Bear Swamp has been reclassified to "Other long-term liabilities" on the Consolidated Balance Sheets. The 2014 and 2015 carrying values have been restated.

reserved to be applied in the 2017 to 2019 period. In addition, the financial benefit resulting from a change in the recognition of tax benefits for the South Canoe and Sable Wind Projects is to be reserved to be applied to the FAM in the 2017 to 2019 period. The exception to this direction is to apply a sufficient amount of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016 that would have been otherwise required. This amount totals $4.6 million. As a result, as at December 31, 2015, NSPI has deferred $4.6 million of excess non-fuel revenues to 2016 and $40.1 million of excess non-fuel revenues for the periods 2017 to 2019.

A settlement agreement, approved by the UARB in November 2014, resulted in approximately $56.0 million of the outstanding FAM balance as at December 31, 2014 being collected in 2015. The settlement agreement also reduced the FAM regulatory asset at the end of 2014 of $86.1 million by $38.2 million via an offset from the liability balance in the Rate Stabilization deferral account, such that at December 31, 2014 the FAM regulatory asset was $47.9 million.

Through a related settlement agreement with stakeholders in December 2014, NSPI agreed to apply non-fuel revenues above that required to achieve its approved range of return to reduce the FAM deferral account. This was effective as of January 1, 2015, and remains until the next General Rate Application (“GRA”) approval or similar process where non-fuel rates are adjusted. This settlement agreement required NSPI to contribute a minimum of $41.3 million to the FAM deferral account by the end of 2015. As at December 31, 2015, NSPI had exceeded the minimum required contribution through the $38.2 million in 2014 referred to above and an additional $26.4 million in 2015. In 2015, NSPI applied $44.7

million in excess non-fuel revenues against the FAM; $18.3 million was the result of the change to South Canoe and Sable Wind Projects tax treatment.

**Regulated Fixed Cost Deferrals**

NSPI has the following regulatory assets arising from UARB approved fixed cost deferral mechanisms:

DSM Deferral

In April 2014, the Government of Nova Scotia announced new energy efficiency legislation to remove a previous charge for conservation and efficiency programs from power bills of Nova Scotia customers effective January 1, 2015. In addition, the legislation requires NSPI to purchase electricity efficiency and conservation activities (“Program Costs”) from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The Program Costs were set for 2015 at $35.0 million and have been deferred as a regulatory asset and recoverable from customers over an eight-year period beginning in 2016. In August 2015, the UARB approved a budget of $102.0 million for the three-year period of 2016 through 2018. The Electricity Plan Act has placed a cap of $34.0 million on the 2019 DSM spending. The 2016 DSM cost of $24.7 million will not be deferred. A decision of the timing of the cost recovery for 2017 through 2019 will be made at a future date.

The Program Costs are recorded in “OM&G”, with an offsetting credit in “Regulated fuel adjustment mechanism and fixed cost deferrals” on Emera’s Consolidated Income Statements, with no effect on net earnings, with the exception of interest on the balance.

The deferred DSM amounts are recognized as a “Regulatory asset” on the Consolidated Balance Sheets. The DSM regulatory asset balance of $36.4 million is disclosed in Note 17 and includes associated interest that is recorded as “Interest expense, net” on the Consolidated Statements of Income.

2013/2014 Rate Stabilization Fixed Cost Recovery Deferral

In December 2012, the UARB approved a deferral of recovery of certain fixed costs for fiscal 2013 and 2014 as part of a rate stabilization plan. As previously noted above under the Regulated Fuel Adjustment Mechanism, the resulting regulatory liability at the end of 2014 of $38.2 million was applied against the FAM regulatory asset balance in 2014 and is included in the application of non-fuel revenues line in the table above.