# Management’s Discussion & Analysis

As at February 15, 2019

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 2018 relative to the same quarter in 2017; the full year of 2018 relative to 2017 and selected financial information for 2016; and its financial position as at December 31, 2018 relative to December 31, 2017. 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. The Company’s activities are currently carried out through six business segments: Emera Florida and New Mexico, Nova Scotia Power Inc., Emera Maine, Emera Caribbean, Emera Energy and Corporate and Other. The Company is reviewing its internal reporting to the chief operating decision maker and considering changes to its reportable segments for 2019.

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, 2018. 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 Equity Investment** | **Accounting Policies Approved/Examined By** |
|---|---|
| **Subsidiary** | |
| Tampa Electric – Electric Division of Tampa Electric Company (“TEC”) | Florida Public Service Commission (“FPSC”) and the Federal Energy Regulatory Commission (“FERC”) |
| Peoples Gas System (“PGS”) – Gas Division of TEC | FPSC |
| SeaCoast Gas Transmission, LLC ("SeaCoast") | FPSC |
| New Mexico Gas Company, Inc. (“NMGC”) | New Mexico Public Regulation Commission (“NMPRC”) |
| Nova Scotia Power Inc. ("NSPI") | Nova Scotia Utility and Review Board (“UARB”) |
| Emera Maine | Maine Public Utilities Commission (“MPUC”) and FERC |
| Barbados Light & Power Company Limited (“BLPC”) | Fair Trading Commission, Barbados ("FTC") |
| Grand Bahama Power Company Limited (“GBPC”) | The Grand Bahama Port Authority (“GBPA”) |
| Dominica Electricity Services Ltd. (“Domlec”) | Independent Regulatory Commission, Dominica (“IRC”) |
| Emera Brunswick Pipeline Company Limited (“Brunswick Pipeline”) | National Energy Board (“NEB”) |
| **Equity Investments** | |
| 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 ("NLPUB") |
| St. Lucia Electricity Services Limited (“Lucelec”) | National Utility Regulatory Commission (“NURC”) |

All amounts are in Canadian dollars ("CAD"), except for the Emera Florida and New Mexico, 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.

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# 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 harbour 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 that could cause results or events to differ from current expectations are discussed in the “Business Overview and 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; liquidity and capital market risk; market for, pricing and timing of select asset sales; future dividend growth; timing and costs associated with certain capital investment; 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 that could reduce demand for electricity; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty 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.

# INTRODUCTION AND STRATEGIC OVERVIEW

Based in Halifax, Nova Scotia, Emera owns and operates cost-of-service rate-regulated electric and gas utilities in Canada, the United States and the Caribbean. Cost-of-service utilities provide essential gas and electric services in designated territories under franchises, and are overseen by regulatory authorities. Emera’s strategic focus is to safely deliver cleaner, affordable and reliable energy to its customers.

Approximately 70 per cent of Emera’s current adjusted earnings are generated from operations in Florida and Nova Scotia. These jurisdictions provide generally stable regulatory and strong economic environments. Approximately 50 per cent of Emera’s assets and current adjusted earnings are from its operations in Florida.

Emera's portfolio of regulated utilities provides reliable earnings, cash flow and dividends. Earnings opportunities in regulated utilities are generally driven by the magnitude of net investment in the utility (known as "rate base"), the amount of equity in the capital structure and the return on equity as allowed through regulation. Earnings are also affected by sales volumes and operating expenses.

Emera has a $6.5 billion capital investment plan over the 2019 to 2021 period, including investing $2.2 billion ($1.7 billion USD) in Florida for Tampa Electric's 600 megawatts ("MW") of new solar generation and the modernization of the Big Bend Power Station. This planned capital investment will be funded primarily through internally generated cash flows, debt raised at the operating company level and select asset sales. Equity capital markets, including the issuance of common and preferred equity and the dividend reinvestment plan will continue to support the company's future capital investments. Maintaining investment-grade credit ratings is a key priority of management.

Emera has provided annual dividend growth guidance of four to five per cent through to 2021. The Company targets a long-term dividend payout ratio of 70 to 75 per cent, and while the payout ratio is likely to exceed that target in the forecast period, it is expected to return to that range over time.

Seasonal patterns and other weather events affect demand and operating costs. Similarly, mark-to-market adjustments and foreign currency exchange can have a material impact on financial results for a specific period. Emera's consolidated net income and cash flows are also impacted by movements in the US dollar relative to the Canadian dollar and benefits from a weaker Canadian dollar. Emera generally hedges transactional exposure (but does not hedge translational exposure). These impacts, as well as the timing of capital investment and other factors mean that results in any one quarter are not necessarily indicative of results in any other quarter or for the year as a whole.

Energy markets worldwide are facing unprecedented change and Emera is well positioned to respond to shifting customer demands, complex regulatory environments and the trend towards de-carbonization. Renewable generation and battery storage are getting both more affordable and efficient. Customers are looking for more choice, control and reliability. Climate change and extreme weather are shaping how utilities operate and how they invest in infrastructure. There is also an overall need to replace aging infrastructure. Emera sees opportunity in these changes. Emera's efforts to fund investments in renewable and technology assets with related fuel or operating cost savings balances the opportunity with managing rate pressure and affordability for customers.

For example, significant investments to facilitate the use of renewable and low-carbon energy include the recently completed Maritime Link in Atlantic Canada, the ongoing construction of new solar generation at Tampa Electric, and the modernization of the Big Bend Power Station at Tampa Electric. All of these projects demonstrate Emera's strategy of finding cleaner ways to meet the energy needs of customers while keeping rates affordable.

Emera is committed to world-class safety, operational excellence, good governance, excellent customer service, reliability, being an employer of choice, and building constructive relationships with regulators, stakeholders and the communities where we operate.

# 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. These measures are discussed and reconciled below.

**Adjusted Net Income**

Emera calculates an adjusted net income measure by excluding the effect of mark-to-market ("MTM") adjustments and the impact in 2017 of US tax reform, signed into law on December 22, 2017 in the *US Tax Cuts and Jobs Act of 2017* ("the Act").

The MTM adjustments are a result of the following:

- the mark-to-market adjustments related to Emera's held-for-trading ("HFT") commodity derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered;
- the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp Power Company LLC ("Bear Swamp");
- the amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the mark-to-market adjustments related to an interest rate swap in Brunswick Pipeline; and
- the mark-to-market adjustments related to equity securities held in Emera Caribbean and Corporate and Other.

Management believes excluding from net 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 and ongoing operations of the business, and allows investors to better understand and evaluate the business. Management and the Board of Directors exclude these mark-to-market adjustments for evaluation of performance and incentive compensation.

In Q4 2017, the Company recorded a non-cash income tax expense resulting from the provisional revaluation of existing US non-regulated net deferred income tax assets. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. The revaluation of an existing asset is not the result of any operational or market driven event. Management therefore believes excluding from net income the effect of this revaluation better distinguishes ongoing operations of the business, and allows investors to better understand and evaluate the Company.

Refer to the "Consolidated Financial Review" section and the "Financial Highlights" sections for Emera Energy, Emera Caribbean and Corporate and Other, for further details on mark-to-market adjustments.

The following reconciles 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 | | |
|---|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 | 2016 |
| Net income (loss) attributable to common shareholders | **$ 231** | $ (228) | **$ 710** | $ 266 | $ 227 |
| Revaluation of US non-regulated deferred income taxes | **$ -** | $ (317) | **$ -** | $ (317) | $ - |
| After-tax mark-to-market gain (loss) | **$ 64** | $ (48) | **$ 39** | $ 59 | $ (248) |
| Adjusted net income attributable to common shareholders | **$ 167** | $ 137 | **$ 671** | $ 524 | $ 475 |
| Earnings per common share – basic | **$ 0.98** | $ (1.06) | **$ 3.05** | $ 1.25 | $ 1.33 |
| Adjusted earnings per common share – basic | **$ 0.71** | $ 0.64 | **$ 2.88** | $ 2.46 | $ 2.77 |

**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. EBITDA is useful in assessing Emera's operating performance and indicates the Company's ability to service or incur debt, invest in capital and finance working capital requirements.

Adjusted EBITDA is a non-GAAP financial measure used by Emera. Similar to adjusted net income calculations described above, this measure represents EBITDA absent the income effect of Emera's mark-to-market adjustments.

The Company's EBITDA and Adjusted EBITDA may not be comparable to EBITDA measures of other companies but, in management's view, appropriately reflect Emera's specific operating performance. 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.

The following is a reconciliation of reported net income to EBITDA and Adjusted EBITDA:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 | 2016 |
| Net income (loss) (1) | **$ 231** | $ (232) | **$ 747** | $ 299 | $ 266 |
| Interest expense, net | **186** | 175 | **713** | 698 | 585 |
| Income tax expense (recovery) | **40** | 329 | **69** | 520 | (22) |
| Depreciation and amortization | **229** | 212 | **916** | 856 | 588 |
| EBITDA | **686** | 484 | **2,445** | 2,373 | 1,417 |
| Mark-to-market gain (loss), excluding income tax and interest | **94** | (75) | **58** | 78 | (327) |
| Adjusted EBITDA | **$ 592** | $ 559 | **$ 2,387** | $ 2,295 | $ 1,744 |

(1) Net income (loss) is income before Non-controlling interest in subsidiaries and Preferred stock dividends.

# CONSOLIDATED FINANCIAL REVIEW

## Significant Items Affecting Earnings

**Earnings Impact of After-Tax Mark-to-Market Gains and Losses**

After-tax mark-to-market increased $112 million to a $64 million gain in Q4 2018, compared to a $48 million loss in Q4 2017, mainly due to changes in Emera Energy's existing contract positions. For the year ended December 31, 2018, after-tax mark-to-market gains decreased $20 million to $39 million, compared to $59 million in 2017. This decrease, primarily related to Emera Energy, was due to a larger reversal of mark-to-market losses in Q1 2017 and changes in existing contract positions, partially offset by lower amortization of gas transportation assets in 2018.

**Florida State Tax Apportionment**

In Q3 2018, Emera received approval from the Florida Department of Economic Opportunity to change its Florida state tax apportionment factors. This change resulted in the Company recording a tax benefit of approximately $23 million, or $0.10 per common share, as a result of the remeasurement of certain deferred tax balances.

**US Tax Reform**

On December 22, 2017, the *Tax Cuts and Jobs Act of 2017* was signed into law. As a result, in Q4 2017, the Company was required to revalue its US deferred income tax assets and liabilities based on the new 21 per cent tax rate. The Company recognized a $317 million income tax expense in 2017 as a result of the provisional revaluation of its US non-regulated net deferred income tax assets. There was no impact to earnings on the revaluation of the utilities' net deferred tax liabilities as the Act allowed for an offsetting regulatory liability.

No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. The measurement period allowed by SEC Staff Accounting Bulletin 118, *Income Tax Accounting Implications of the Tax Cuts and Jobs Act* ("SAB 118") is now closed.

On November 26, 2018, the Internal Revenue Service ("IRS") issued proposed regulations on the interest deductibility limitation rules legislated under the Act. The Company believes its US based financing interest will be deductible under the Act.

Emera's effective tax rate for 2018 was 8 per cent. Absent the reduction of the US federal corporate income tax rate, the effective tax rate would have been 13 per cent. For further details on the effective tax rate, refer to note 7 to the consolidated financial statements for the year ended December 31, 2018.

# Consolidated Financial Highlights by Business Segment

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| **Adjusted Net Income** | **2018** | 2017 | **2018** | 2017 | 2016 |
| Emera Florida and New Mexico | **$ 101** | $ 80 | **$ 428** | $ 382 | $ 172 |
| NSPI | **28** | 23 | **131** | 129 | 130 |
| Emera Maine | **11** | 8 | **44** | 46 | 47 |
| Emera Caribbean | **14** | 1 | **45** | 31 | 100 |
| Emera Energy | **44** | 26 | **120** | 24 | 24 |
| Corporate and Other | **(31)** | (1) | **(97)** | (88) | 2 |
| Adjusted net income attributable to common shareholders | **$ 167** | $ 137 | **$ 671** | $ 524 | $ 475 |
| Revaluation of US non-regulated deferred income taxes | **-** | (317) | **-** | (317) | - |
| After-tax mark-to-market gain (loss) | **64** | (48) | **39** | 59 | (248) |
| Net income (loss) attributable to common shareholders | **$ 231** | $ (228) | **$ 710** | $ 266 | $ 227 |

The following table highlights the significant changes in adjusted net income from 2017 to 2018:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Adjusted net income – 2017** | **$ 137** | **$ 524** |
| Emera Energy | 18 | 96 |
| Emera Florida and New Mexico | 21 | 46 |
| Emera Caribbean | 13 | 14 |
| NSPML and LIL equity earnings | (4) | 14 |
| Florida state tax apportionment | - | 23 |
| Other | (18) | (46) |
| **Adjusted net income – 2018** | **$ 167** | **$ 671** |

Refer to the segment "Financial Highlights" section for further details of business unit contributions.

| For the<br>millions of Canadian dollars | | | Year ended<br>December 31 |
|---|---|---|---|
| | **2018** | 2017 | 2016 |
| Operating cash flow before changes in working capital | **$ 1,806** | $ 1,297 | $ 919 |
| Change in working capital | **(116)** | (104) | 134 |
| Operating cash flow | **$ 1,690** | $ 1,193 | $ 1,053 |
| Investing cash flow | **$ (2,190)** | $ (1,761) | $ (9,037) |
| Financing cash flow | **$ 344** | $ 593 | $ 7,448 |

| As at<br>millions of Canadian dollars | **2018** | 2017 | December 31<br>2016 |
|---|---|---|---|
| Total assets | **$ 32,314** | $ 28,806 | $ 29,271 |
| Total long-term debt (including current portion) | **$ 15,411** | $ 13,881 | $ 14,744 |

Refer to the "Consolidated Cash Flow Highlights" section for further discussion of cash flow.

# Consolidated Income Statement Highlights

| For the<br>millions of Canadian dollars<br>(except per share amounts) | Three months ended<br>December 31 | | Variance | Year ended<br>December 31 | | Variance | Year ended<br>December 31 |
|---|---|---|---|---|---|---|---|
| | **2018** | 2017 | | **2018** | 2017 | | 2016 |
| Operating revenues | **$ 1,799** | $ 1,473 | $ 326 | **$ 6,524** | $ 6,226 | $ 298 | $ 4,277 |
| Operating expenses | **1,368** | 1,231 | (137) | **5,126** | 4,808 | (318) | 3,722 |
| Income from operations | **431** | 242 | 189 | **1,398** | 1,418 | (20) | 555 |
| Income from equity investments | **33** | 34 | (1) | **154** | 124 | 30 | 100 |
| Other income (expenses) | **(7)** | (4) | (3) | **(23)** | (25) | 2 | 174 |
| Interest expense, net | **186** | 175 | (11) | **713** | 698 | (15) | 585 |
| Income tax expense (recovery) | **40** | 329 | 289 | **69** | 520 | 451 | (22) |
| Net income (loss) | **231** | (232) | 463 | **747** | 299 | 448 | 266 |
| Net income (loss) attributable to common shareholders | **231** | (228) | 459 | **710** | 266 | 444 | 227 |
| Revaluation of US non-regulated deferred income taxes | **-** | (317) | 317 | **-** | (317) | 317 | - |
| After-tax mark-to-market gain (loss) | **64** | (48) | 112 | **39** | 59 | (20) | (248) |
| Adjusted net income attributable to common shareholders | **$ 167** | $ 137 | $ 30 | **$ 671** | $ 524 | $ 147 | $ 475 |
| Earnings per common share – basic | **$ 0.98** | $ (1.06) | $ 2.04 | **$ 3.05** | $ 1.25 | $ 1.80 | $ 1.33 |
| Earnings per common share – diluted | **$ 0.98** | $ (1.06) | $ 2.04 | **$ 3.04** | $ 1.24 | $ 1.80 | $ 1.32 |
| Adjusted earnings per common share – basic | **$ 0.71** | $ 0.64 | $ 0.07 | **$ 2.88** | $ 2.46 | $ 0.42 | $ 2.77 |
| Dividends per common share declared | **$ -** | $ - | $ - | **$ 2.2825** | $ 2.1325 | $ 0.1500 | $ 1.9950 |
| Adjusted EBITDA | **$ 592** | $ 559 | $ 33 | **$ 2,387** | $ 2,295 | $ 92 | $ 1,744 |

**Operating Revenues**

For the fourth quarter of 2018, operating revenues increased $326 million, compared to the fourth quarter of 2017. Absent increased mark-to-market gains of $174 million, operating revenues increased $152 million due to:

- $79 million increase at Emera Florida and New Mexico due to the impact of a stronger USD, higher electric sales volumes due to customer growth, weather and rates related to completed solar projects at Tampa Electric;
- $30 million increase at NSPI as a result of increased sales volumes due to load growth and weather;

- $35 million increase at Emera Energy reflecting significant pipeline maintenance that reduced marketing and trading margins on hedged capacity in Q4 2017 and higher capacity prices for its New England Gas Generation ("NEGG") fleet in Q4 2018.

Operating revenues increased $298 million for the year ended December 31, 2018, compared to 2017. Absent decreased mark-to-market gains of $22 million, operating revenues increased $320 million due to:

- $126 million increase at NEGG reflecting higher capacity prices and more favourable market conditions in 2018, and an unplanned outage at the Bridgeport facility in 2017;
- $102 million increase at NSPI as a result of increased sales volumes due to load growth and weather, the 2017 refund to customers of 2016 over-recovery of fuel costs, and increased fuel-related electricity pricing, partially offset by the impact of the Maritime Link assessment;
- $71 million increase in marketing and trading margin at Emera Energy Services ("EES"), driven primarily by the impact of cold weather in Q1 2018, warm weather in Q3 2018 and significant pipeline maintenance that reduced margins on hedged capacity in Q4 2017;
- $52 million increase at Emera Florida and New Mexico as a result of higher clause recoveries and favourable customer growth in PGS and favourable weather in Florida and New Mexico, higher electric sales volumes due to weather and higher base rates related to solar projects and the Polk Power Station expansion at Tampa Electric. These increases were partially offset by lower commodity costs in New Mexico; and
- $26 million decrease at Bayside Power due to lower electricity sales reflecting renegotiation of the Bayside Power power purchase agreement ("PPA").

**Operating Expenses**

For the fourth quarter of 2018, operating expenses increased $137 million, compared to the fourth quarter of 2017. Absent decreased mark-to-market gains of $3 million, operating expenses increased $134 million due to:

- $90 million increase at Emera Florida and New Mexico as a result of increased operating, maintenance and general ("OM&G") at Tampa Electric resulting from the regulatory agreement to net storm costs and the 2018 tax reform benefits, and the impact of a stronger USD;
- $22 million increase at Corporate and Other mainly due to higher performance based compensation accruals; and
- $14 million increase at NSPI due to increased fuel costs as a result of payment of the Maritime Link assessment and increased commodity prices, increased OM&G due to higher storm costs, partially offset by decreased fuel adjustment mechanism ("FAM") and fixed cost deferrals.

Operating expenses increased $318 million for the year ended December 31, 2018, compared to 2017. Absent increased mark-to-market gains of $6 million, operating expenses increased $324 million due to:

- $175 million increase at Emera Florida and New Mexico as a result of increased OM&G at Tampa Electric from the regulatory agreement to net storm costs and the 2018 tax reform benefits;
- $88 million increase at NSPI due to increased fuel costs as a result of payment of the Maritime Link assessment and increased commodity pricing, partially offset by decreased FAM and fixed cost deferrals;
- $60 million increase at NEGG due to an increase in generation volumes in 2018 reflecting the impact of the unplanned outage at Bridgeport Energy in 2017 and more favourable market conditions in 2018;
- $56 million increase in depreciation and amortization due to normal asset growth across the business; and
- $26 million decrease at Bayside Power due to decreased natural gas purchases reflecting renegotiation of the Bayside Power PPA.

**Income from Equity Investments**

Income from equity investments increased $30 million for the year ended December 31, 2018, compared to 2017, due to increased capacity prices at Bear Swamp and higher equity earnings from NSPML and LIL.

**Income Tax Expense**

The decrease in income tax expense for the fourth quarter of 2018, compared to the same period in 2017, was due to the reduction of the US federal corporate income tax rate, partially offset by increased income before provision for income taxes. The reduction of the US federal corporate income tax rate resulted in a $339 million decrease in income tax expense for the quarter, including the $317 million income tax expense recognized in Q4 2017 related to the revaluation of the Company’s US non-regulated net deferred income tax assets at the new tax rate.

The decrease in income tax expense for the year ended December 31, 2018, compared to 2017, was due to the reduction of the US federal corporate income tax rate, amortization of deferred tax regulatory liabilities in the US utilities and remeasurement of certain deferred tax balances as a result of a change in Florida state tax apportionment factors. The reduction of the US federal corporate income tax rate resulted in a $405 million decrease in income tax expense for the year ended December 31, 2018, including the $317 million income tax expense recognized in 2017 related to the revaluation of the Company’s US non-regulated net deferred income tax assets at the new tax rate.

As a result of the *US Tax Cuts and Jobs Act of 2017*, the US federal corporate income tax rate was reduced from 35 per cent to 21 per cent. This reduction resulted in a significant decrease in income tax expense, as described above, however the net impact to earnings was minimal. This was a result of the favourable impact of the reduced tax rate on Emera Energy earnings which was offset by the unfavourable impact of reduced tax recovery on losses arising from Corporate borrowing costs. The net impact on US based regulated utilities earnings was immaterial. Tax benefits from the reduced rates in Tampa Electric were netted against deferred storm costs for 2018. Tax benefits deferred by PGS were netted against the amortization of its manufactured gas plant (“MGP”) environmental regulatory asset in 2018. Tampa Electric and PGS tax benefits will be adjusted in rates starting in 2019. As of December 31, 2018, NMGC recorded a regulatory liability of $8 million USD, to reflect 2018 tax reform benefits, which are being addressed through ongoing rate case proceedings. Certain of the tax benefits for Emera Maine are reflected in rates effective July 1, 2018 with other components being deferred to be addressed in future regulatory proceedings.

**Net Income and Adjusted Net Income Attributable to Common Shareholders**

For the fourth quarter in 2018, net income attributable to common shareholders was favourably impacted by the $317 million 2017 revaluation of US non-regulated deferred income taxes and the $112 million increase in after-tax mark-to-market gains primarily related to Emera Energy. Absent the 2017 revaluation of US non-regulated deferred income taxes and favourable mark-to-market changes, adjusted net income attributable to common shareholders increased $30 million due to higher contributions from Emera Energy and Emera Florida and New Mexico, partially offset by decreased contributions from Corporate and Other.

For the year ended December 31, 2018 net income attributable to common shareholders was favourably impacted by the $317 million 2017 revaluation of US non-regulated deferred income taxes, partially offset by the $20 million decrease in after-tax mark-to-market gains primarily related to Emera Energy. Absent the 2017 revaluation of US non-regulated deferred income taxes and unfavourable mark-to-market changes, adjusted net income attributable to common shareholders increased $147 million. The increase was due to higher contributions from Emera Energy, Emera Florida and New Mexico and NSPML and LIL, and the tax benefit recorded as a result of remeasurement of certain deferred tax balances due to the change in Florida state tax apportionment factors, partially offset by decreased contributions from Corporate and Other.

**Earnings and Adjusted Earnings per Common Share – Basic**

Earnings per common share – basic were higher for the fourth quarter and for the year ended December 31, 2018 due to the results of the revaluation of US non-regulated deferred income taxes in 2017 and higher earnings in 2018, partially offset by the impact of the increase in the weighted average number of common shares outstanding reflecting the issuance of shares in December 2017.

Adjusted earnings per common share – basic were higher for the fourth quarter and for the year ended December 31, 2018 due to higher adjusted earnings, partially offset by the increase in the weighted average of common shares outstanding.

**Effect of Foreign Currency Translation**

Emera operates internationally, including in Canada, the US and various Caribbean countries. As such, the Company generates revenues and incurs expenses denominated in local currencies which are translated into Canadian dollars for financial reporting. Changes in translation rates, particularly in the value of the US dollar against the Canadian dollar, can positively or adversely affect results.

Earnings from Emera's foreign operations are translated into Canadian dollars. In general, Emera's earnings benefit from a weakening Canadian dollar and are adversely impacted by a strengthening Canadian dollar. The impact of foreign exchange in any period is driven by rate changes, the timing of earnings from foreign operations during the period, and the percentage of earnings from foreign operations in the period.

Results of operations from foreign operations are translated at the weighted average rate of exchange and assets and liabilities of foreign operations are translated at period end rates. The relevant CAD/USD exchange rates for 2018 and 2017 are as follows:

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| Weighted average CAD/USD exchange rate | **$ 1.32** | $ 1.27 | **$ 1.30** | $ 1.30 |
| Period end CAD/USD exchange rate | **$ 1.36** | $ 1.25 | **$ 1.36** | $ 1.25 |

The weakening of the CAD increased earnings by $9 million and adjusted earnings by $7 million in Q4 2018 compared to Q4 2017. The weakening of the CAD increased earnings by $1 million and adjusted earnings by $4 million in 2018, compared to 2017.

Consistent with the Company's risk management policies, Emera partially manages currency risks through matching US denominated debt to finance its US operations and uses short-term foreign currency derivative instruments to hedge specific transactions. Emera does not utilize derivative financial instruments for foreign currency trading or speculative purposes.

The table below includes Emera's significant segments whose contributions to adjusted earnings are recorded in US dollar currency.

| millions of US dollars | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| Emera Florida and New Mexico | **$ 77** | $ 63 | **$ 331** | $ 295 |
| Emera Maine | **9** | 7 | **34** | 36 |
| Emera Caribbean | **11** | 1 | **35** | 24 |
| Emera Energy (1) | **35** | 19 | **100** | 21 |
| | **132** | 90 | **500** | 376 |
| Corporate and Other (2) | **(33)** | (29) | **(130)** | (116) |
| **Total** (3) | **$ 99** | $ 61 | **$ 370** | $ 260 |

(1) Includes Emera Energy's US dollar adjusted net income from EES, NEGG and Bear Swamp.

(2) Corporate and Other includes interest expense on US dollar denominated debt, net of interest income on an intercompany US dollar loan to Emera Energy.

(3) Amounts above do not include the impact of mark-to-market or US tax reform.

# BUSINESS OVERVIEW AND OUTLOOK

Earnings from Emera's regulated utilities are most directly impacted by the rate of return on equity ("ROE") or rate base and capital structure approved by their regulators, the prudent management of operating costs, the approved recovery of regulatory deferrals, energy sales volumes including the impact of weather, and the timing and amount of capital expenditures. Electric and gas sales volumes are primarily driven by general economic conditions, population and weather. Emera's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. The electric and gas utilities' industrial customers include manufacturing facilities and other large volume operations.

## Emera Florida and New Mexico

Emera Florida and New Mexico includes TECO Energy, the parent company of TEC, NMGC, SeaCoast and TECO Finance. TEC consists of two divisions; Tampa Electric, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity serving customers in West Central Florida, and PGS, a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas serving customers in Florida. NMGC is a regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas serving customers in New Mexico. SeaCoast is a regulated intrastate natural gas transmission company offering services in Florida.

**Tampa Electric**

With approximately $7.8 billion USD of assets and approximately 764,000 customers at December 31, 2018, Tampa Electric owns 5,238 MW of generating capacity, of which 77 per cent is natural gas-fired, 20 per cent is coal and petroleum coke ("petcoke") and 3 per cent is solar. Tampa Electric owns 2,150 kilometres of transmission facilities and 18,750 kilometres of distribution facilities.

Tampa Electric's approved regulated ROE range is 9.25 per cent to 11.25 per cent, based on an allowed equity capital structure of 54 per cent. An ROE of 10.25 per cent is used for the calculation of the return on investments for clauses.

**Peoples Gas System**

With approximately $1.4 billion USD of assets and approximately 392,000 customers, the PGS system includes approximately 20,920 kilometres of natural gas mains and 11,910 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2.0 billion therms in 2018.

The approved ROE range for PGS is 9.25 per cent to 11.75 per cent, based on an allowed equity capital structure of 54.7 per cent. Absent any rate case filing, the bottom of the range will increase to 9.75 per cent in 2021. An ROE of 10.75 per cent is used for the calculation of return on investments for clauses.

**New Mexico Gas Company, Inc.**

With over $1.3 billion USD of assets and approximately 530,000 customers, NMGC serves approximately 60 per cent of the state's population in 23 of New Mexico's 33 counties. NMGC's system includes approximately 2,640 kilometres of transmission lines and 17,040 kilometres of distribution lines. Annual natural gas throughput was approximately 825 million therms in 2018.

The approved ROE for NMGC is 10 per cent, on an allowed equity capital structure of 52 per cent. NMGC's rates were established in a 2012 rate case settlement and were frozen until December 31, 2017 per the June 2016 NMPRC order (the "Order") approving Emera's acquisition of TECO Energy. NMGC filed a rate case, including the prospective impact of tax reform, on February 26, 2018. A hearing in the rate case was held September 24, 2018, when an uncontested stipulation on the rate request was presented. A second hearing in the rate case, related to 2018 tax reform benefits, was held December 17, 2018. Decisions by the NMPRC on the rate case and on 2018 tax reform benefits are expected in 2019.

**Emera Florida and New Mexico Outlook**

The Florida utilities anticipate earning within their allowed ROE ranges in 2019 and expect rate base and earnings to be higher than prior years. Tampa Electric expects customer growth rates in 2019 to be consistent with 2018, reflective of economic growth in Florida. Assuming normal weather in 2019, Tampa Electric sales volumes are expected to be consistent with 2018 sales volumes which benefited from favourable weather. PGS expects customer growth rates in 2019 to be consistent with 2018, reflective of economic growth in Florida and the optimization of existing opportunities as the utility increases its market penetration in Florida. Assuming normal weather in 2019, PGS sales volumes are expected to increase at a level lower than customer growth as 2018 energy sales benefited from favourable weather.

In September 2018, Tampa Electric announced its intention to invest approximately $235 million USD during 2018 through 2022 for its advanced metering infrastructure ("AMI") project.

In May 2018, Tampa Electric announced its intention to invest approximately $850 million USD during 2018 through 2023 to modernize the Big Bend Power Station. Refer to the "Developments" section for further details.

In September 2017, Tampa Electric announced its intention to invest approximately $850 million USD over four years in new utility-scale solar photovoltaic projects across its service territory. On November 6, 2017, the FPSC approved a settlement agreement allowing a solar base rate adjustment ("SoBRA") that provides for the recovery, upon in-service, of up to 600 MW of investments in utility-scale solar projects phased in from late 2018 through early 2021. On May 8, 2018, the FPSC approved Tampa Electric's first SoBRA. This SoBRA represents 145 MW and $24 million USD annually in estimated revenue requirements and Tampa Electric began collecting these revenues in September 2018. On October 29, 2018, the FPSC approved Tampa Electric's second SoBRA. This SoBRA represents 260 MW and $46 million USD annually in estimated revenue requirements and Tampa Electric began collecting these revenues in January 2019.

In September 2017, Tampa Electric was impacted by Hurricane Irma and incurred restoration costs of approximately $102 million USD. The amount charged to the storm reserve exceeded the balance in the reserve by $47 million USD. On December 28, 2017, Tampa Electric petitioned the FPSC for recovery of estimated restoration costs in excess of the storm reserve for several named storms and to replenish the reserve to the $56 million USD level that existed as of October 31, 2013. On March 1, 2018, the FPSC approved a settlement agreement filed by Tampa Electric authorizing the utility to net the amount of storm cost recovery against its return of estimated 2018 US tax reform benefits to customers, effective April 1, 2018. In Q1 2018, Tampa Electric recorded OM&G expense and a regulatory liability of $19 million USD to offset tax reform benefits. This deferral was amortized over the balance of the year as a credit against recognition of storm expense. In total, OM&G expense due to the allowed netting of the storm cost recovery with tax reform benefits, net of amortization of first quarter tax reform benefits, was approximately $22 million USD for Q4 2018 and $103 million USD for the year ended December 31, 2018.

Tampa Electric's final storm costs subject to netting will be determined in a separate regulatory proceeding in 2019. Any difference will be trued up and returned to customers in 2020. On August 20, 2018, the FPSC approved a reduction in base rates of $103 million USD annually beginning in 2019 to reflect the impact of tax reform.

On September 12, 2018, the FPSC approved a settlement agreement filed by PGS, authorizing the utility to amortize $11 million USD of its MGP environmental regulatory asset and net it against its estimated 2018 tax reform benefits. Beginning in January 2019, PGS lowered base rates by $12 million USD to reflect the impact of tax reform and reduced depreciation rates by $10 million USD, in accordance with the settlement agreement.

NMGC expects 2019 earnings and rate base to be higher than prior years. Customer growth rates are expected to be consistent with 2018, reflecting expectations for housing starts and new connections.

In 2019, Emera Florida and New Mexico expects to invest approximately $1.3 billion USD in capital projects, including allowance for funds used during construction ("AFUDC"), compared to $1.2 billion USD in 2018. Capital projects include supporting normal system reliability and growth at the three utilities. Tampa Electric's investments include the modernization of the Big Bend Power Station, solar projects and AMI. AFUDC will be earned during the construction periods.

PGS will make investments in 2019 to expand its system and support customer growth, including expected investments related to compressed natural gas fueling stations and liquefied natural gas facilities, and continued replacement of obsolete plastic, cast iron and bare steel pipe.

On April 4, 2018, SeaCoast executed an agreement with Seminole Electric Cooperative, Inc. ("Seminole") to provide long-term firm gas transportation service to Seminole's new gas-fired generating facility being constructed in Putnam County, Florida. SeaCoast will construct and operate a 21-mile, 30-inch pipeline lateral that is anticipated to go into service by 2022. The estimated capital investment is projected to be in the range of $100 million to $120 million USD with the majority of the investment expected in 2020 and 2021.

NMGC will complete planning phases of the Santa Fe Mainline Looping project in 2019, and will continue to invest in system improvements by replacing legacy pipe and making pipeline integrity management improvements.

# NSPI

NSPI is a vertically integrated regulated electric utility. It is the primary electricity supplier in Nova Scotia, Canada. NSPI has approximately $5.1 billion of assets and provides electricity generation, transmission and distribution services to approximately 519,000 customers. The Company owns 2,441 MW of generating capacity, of which approximately 43 per cent is coal-fired; 28 per cent is natural gas and/or oil; 20 per cent is hydro and wind; 7 per cent is petcoke and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPPs own 546 MW of capacity. NSPI owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities.

NSPI's approved regulated ROE range 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 per cent. NSPI anticipates earning within its allowed ROE range in 2019 and expects modest rate base growth which will deliver a similar modest increase in earnings.

In December 2015, the *Electricity Plan Implementation (2015) Act ("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. NSPI is currently operating under a Rate Stability Plan for fuel costs for 2017 through 2019 which includes an average annual rate increase of 1.5 per cent for each of these three years.

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 investments have been made in renewable generation and system reliability projects.

NSPI is subject to environmental regulations as set by both the Province of Nova Scotia and the Government of Canada. NSPI continues to work with both levels of government to comply with these regulations, maximizing efficiency of emission control measures and minimizing customer cost. NSPI anticipates that any costs prudently incurred to achieve the legislated reductions will be recoverable from customers under NSPI's regulatory framework.

The Government of Canada ("the Government") introduced the Pan-Canadian Framework on Clean Growth and Climate Change ("the Framework") in early 2017. As part of the Framework, in February 2018, the Government introduced proposed changes to the greenhouse gas ("GHG") coal regulations designed to remove coal fired generation by 2030, subject to equivalency agreements. At that time, a regulation was introduced specifying the emission intensities required for new natural gas fired generation and for boiler conversions from coal to natural gas. The Government published final regulations for both coal and natural gas generation in December 2018. NSPI expects the changes to equivalency agreements to be finalized in 2019. This agreement allows NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent. Beginning January 1, 2019, each province and territory in Canada is required to have a carbon pricing system which meets a benchmark set by the Government. On October 23, 2018, the Government of Canada confirmed that the cap and trade carbon pricing system proposed by the Government of Nova Scotia met the federal benchmark. The Government of Nova Scotia has published final details on the program regarding registration and operating rules. NSPI was granted 22 million metric tons of carbon dioxide allowances for the four year compliance period of 2019 through 2022. The Government of Canada is continuing to develop a clean fuel standard with the expectation that it will not apply to the electricity sector until 2022 at the earliest. NSPI anticipates any prudently incurred costs required to comply with the Framework, and the cap and trade pricing system, will be recoverable from customers.

In November 2018, the Government of Canada presented the 2018 Federal Fall Economic Statement ("the Statement"). The Statement introduced proposed legislation that will provide for the immediate expensing of 100 per cent of the cost of specified clean energy equipment and increased first-year tax depreciation for eligible property. Once enacted, these measures will apply to eligible property that is acquired after November 20, 2018 and available for use before 2028. These measures will impact the timing of tax deductions related to NSPI's investment in property, plant and equipment.

In June 2018, the UARB approved NSPI's $133 million capital application to upgrade customers to AMI. NSPI will commence installation of AMI in 2019 and expects the full AMI project to be completed in 2021.

In 2019, NSPI expects to invest approximately $340 million, including AFUDC, in capital projects, compared to $348 million in 2018. NSPI is investing in projects which will support system reliability and AMI.

# Emera Maine

Emera Maine is a transmission and distribution ("T&D") regulated electric utility with assets of approximately $1.2 billion USD serving approximately 159,000 customers in the State of Maine. Emera Maine owns and operates approximately 2,000 kilometres of transmission facilities and 10,000 kilometres of distribution facilities. Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the energy delivered through Emera Maine's T&D networks.

Approximately 44 per cent of Emera Maine's operating revenue represents distribution operations, 46 per cent is associated with transmission operations and 10 per cent relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

In June 2018, the MPUC approved a 5.3 per cent distribution rate increase. This increase was effective July 1, 2018 and is based on a 9.35 per cent ROE and a common equity component of 49 per cent. Prior to July 1, 2018, the allowed ROE was 9.0 per cent, on a common equity component of 49 per cent.

There are currently four pending complaints filed with the FERC to challenge the base ROE under the ISO-New England ("ISO-NE") Open Access Transmission Tariff ("OATT"). On October 16, 2018, the FERC issued an order that addressed all four complaint proceedings. The FERC order proposed a new methodology to set ROEs. Based on the new methodology, the FERC's preliminary finding was a 10.41 per cent base ROE for the ISO-NE OATT. The FERC has permitted parties to comment on the new methodology and its application to the four pending complaint proceedings. The current reserve is expected to be sufficient to cover the impact of this preliminary finding. For further discussion on the complaints, refer to note 26 to the consolidated financial statements for the year ended December 31, 2018.

Emera Maine's 2019 rate base is expected to grow modestly due to ongoing investment in transmission and distribution infrastructure, resulting in modest growth in earnings.

In 2019, Emera Maine expects to invest approximately $70 million USD (2018 – $76 million USD), primarily on transmission and distribution capital projects supporting normal system reliability.

# Emera Caribbean

Emera Caribbean represents Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities including BLPC, a vertically integrated utility that is the sole provider of electricity in Barbados; GBPC, a vertically integrated utility that is the sole provider of electricity on Grand Bahama Island and a 51.9 per cent interest in Domlec, a vertically integrated utility on the island of Dominica. ECI also holds a 19.1 per cent indirect interest in Lucelec, a vertically integrated utility on the island of St. Lucia which is accounted for on the equity basis.

**BLPC**

With approximately $380 million USD of assets and approximately 130,000 customers, BLPC owns 249 MW of generating capacity, of which 96 per cent is oil-fired and 4 per cent is solar. BLPC owns approximately 168 kilometres of transmission facilities and 2,800 kilometres of distribution facilities. BLPC's approved regulated return on rate base is 10.0 per cent.

**GBPC**

With approximately $300 million USD of assets and approximately 19,000 customers, GBPC owns 98 MW of oil-fired generation, approximately 138 kilometres of transmission facilities and 860 kilometres of distribution facilities. In December 2018, the GBPA approved GBPC's regulated return on rate base of 8.44 per cent for 2019. On January 15, 2018, Emera completed the acquisition of the common shares held by the minority shareholders of ICD Utilities Limited ("ICDU"), increasing the Company's interest in GBPC from 80.4 per cent to 100 per cent.

**Domlec**

Domlec serves approximately 26,000 customers. Domlec owns 27 MW of generating capacity of which 74 per cent is oil-fired and 26 per cent is hydro. Domlec owns approximately 452 kilometres of transmission facilities and 635 kilometres of distribution facilities. Domlec's approved regulated return on rate base is 15.0 per cent.

**Emera Caribbean Outlook**

With oil being the predominant fuel source for generation of electricity in the Caribbean, and with fuel costs directly passed through electricity rates to customers, any change in global fuel prices and resulting change in fuel costs will result in a similar change in customer rates and reported revenues. GBPC has implemented fuel hedging strategies to provide increased certainty to customers as to fuel costs and electricity rates. In support of reducing carbon emissions and exposure to carbon-based fuel sources, more efficient and renewable energy generation and battery storage investments are being developed in the Caribbean.

In 2018, S&P issued several long- and short-term currency ratings changes and changes in ratings on certain bonds for Barbados. These ratings changes are not expected to have a material impact on BLPC.

On December 18, 2018, the Government of Barbados signed the *Income Tax Amendment Act* into law. The legislation, effective January 1, 2019, created a new corporate income tax rate schedule and eliminated certain tax credits. At the date of enactment, BLPC was required to remeasure its deferred income tax liability at its new lower corporate income tax rate, resulting in recognition of an income tax recovery, the majority of which was deferred as a regulatory liability. These changes had minimal impact on 2018 earnings and are expected to have minimal impact on future earnings.

Earnings from Emera Caribbean's utilities in 2019 are expected to be consistent with 2018.

Emera Caribbean plans to invest approximately $120 million USD in capital programs in 2019 (2018 - $68 million USD). This increase is due to investment in new, efficient oil based generation and renewable generation partially offset by lower spending at Domlec due to the completion of hurricane restoration in 2018.

# Emera Energy

Emera Energy includes Emera Energy Services ("EES"), a wholly owned physical energy marketing and trading business; Emera Energy Generation ("EEG"), a wholly owned portfolio of electricity generation facilities in New England and the Maritime provinces of Canada; and an equity investment in a 50.0 per cent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts. On November 26, 2018, Emera announced an agreement to sell its three New England Gas Generating facilities. The transaction is expected to close in the first quarter of 2019. Refer to the "Developments" section for further details.

Earnings from EES are 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 and demand factors, can provide higher levels of margin opportunity. The business is seasonal, with Q1 and Q4 generally providing the greatest opportunity for earnings. Under normal market conditions, the business is generally expected to deliver adjusted net earnings of $15 to $30 million USD ($45 to $70 million USD of margin), with the opportunity for upside when market conditions present.

Earnings from EEG's assets are largely dependent on market conditions, particularly the relative pricing of electricity and natural gas and the absolute price of natural gas as the marginal fuel in the supply stack, and capacity pricing in ISO-NE for NEGG. Efficient operations of the fleet to ensure unit availability, cost management, and effective commercial management are key success factors. Earnings from EEG will be lower in 2019 due to the pending sale of the NEGG facilities.

In 2019, Emera Energy expects to invest approximately $10 million (2018 – $34 million) in capital projects related to its generating assets to continue to improve reliability. This decrease is due to the expected sale of the NEGG facilities.

# Corporate and Other

## Corporate

Corporate encompasses certain corporate-wide functions including executive management, strategic planning, treasury services, legal, 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” and costs associated with corporate activities that are not directly allocated to the operations of Emera’s subsidiaries and investments.

## Other

Other includes the following consolidated and non-consolidated investments:

**Consolidated Investments**

- Brunswick Pipeline, a regulated 145-kilometre pipeline that transports natural gas from Saint John, New Brunswick, to markets in the northeastern United States. The pipeline is contracted under a 25-year firm service agreement with Repsol Energy Canada that expires in 2034. The service agreement is accounted for as a direct financing lease.

- Emera Reinsurance Limited, a captive insurance company providing insurance and reinsurance to Emera and certain of its affiliates, to enable more cost efficient management of risk and deductible levels across Emera.

- Emera Utility Services (“EUS”), a utility services contractor primarily operating in Atlantic Canada.

- Emera US Holdings Inc., a wholly owned holding company for certain of Emera’s assets located in the United States.

- Emera US Finance LP, a wholly owned financing subsidiary of Emera.

- Emera Newfoundland & Labrador Holdings Inc. (“ENL”), holding Emera’s non-consolidated investments in NSPML and LIL which are accounted for on the equity basis. These two transmission investments are related to the development of an 824 MW hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador. See below for additional information on ENL.

**Non-consolidated Investments Accounted for on the Equity Basis**

- Emera’s 100 per cent investment in NSPML, a $1.56 billion transmission project, including two 170-kilometre subsea cables, connecting the island of Newfoundland and Nova Scotia. This project completed commissioning and entered service on January 15, 2018.

- Emera’s 49.5 per cent investment in the partnership capital of LIL, a $3.7 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Construction of the LIL has been completed and the energization phase of the project began in June 2018. On June 27, 2018, Nalcor Energy recognized the first flow of energy from Labrador to Newfoundland and continues to work towards finalizing commissioning activities.

- Emera’s 12.9 per cent investment in M&NP.

Corporate and Other includes corporate financing costs, earnings as a result of the equity investment in Maritime Link and the Labrador Island Link, project-based construction services activity by Emera Utility Services and capital lease accounting treatment of the Emera Brunswick Pipeline, which yields declining earnings over the life of the asset. The segment also includes corporate related costs that are dependent on the level of business development activity and acquisition-related initiatives.

Corporate and Other's costs are expected to be higher in 2019 due to lower intercompany revenue on intercompany financings as a result of the expected sale of NEGG facilities in Q1 2019; increased preferred dividend expense due to additional preferred shares issued in 2018; and lower tax recoveries due to the change in Florida state tax apportionment factors that resulted in the remeasurement of certain deferred tax balances in 2018.

Corporate and Other, excluding ENL as discussed below, expects to spend approximately $10 million on property, plant and equipment in 2019 (2018 - $41 million).

**ENL**

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

Through its subsidiary, NSP Maritime Link Inc., ENL has invested, $1.8 billion of equity, debt and working capital, including $209 million of AFUDC, in development of the Maritime Link Project. Project to date, ENL has invested $545 million in equity, comprised of $452 million in equity contributed and $93 million of accumulated retained earnings, with the remaining being funded with working capital and debt. The project debt has been guaranteed by the Government of Canada.

The Maritime Link entered service on January 15, 2018 and provides for the transmission of energy as well as improved reliability and ancillary benefits, supporting the efficiency and reliability of both provinces. The Maritime Link will transmit at greater capacity when the Lower Churchill project is complete. In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI. Prior to Q1 2018, NSPML recorded non-cash AFUDC earnings as it was under construction. All major contracts have been concluded.

Future equity earnings contributions from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. The approved ROE is 9 per cent.

In 2019, NSPML expects to invest approximately $20 million in capital related to construction close-out costs.

*Labrador Island Link ("LIL")*

ENL is a limited partner with Nalcor Energy in LIL, with total project costs currently estimated at $3.7 billion. Equity earnings are recorded based on an annual ROE of 8.5 per cent of the equity invested. The ROE is approved by the NLPUB.

Earnings from the LIL investment are based on the book value of the equity investment and the approved ROE. Emera's current equity investment is $534 million, and is forecasted to be $579 million by the end of 2019, comprised of $410 million in equity contribution and an estimated $169 million of accumulated equity earnings. Emera's total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $600 million by 2020 when all Lower Churchill projects, including Muskrat Falls, are forecasted by Nalcor Energy to be placed in service.

Cash earnings and return of equity are forecasted by Nalcor Energy to begin in 2020 and until that point Emera will continue to record AFUDC earnings, with such earnings capitalized to its equity investment.

Equity earnings from NSPML and LIL are expected to be modestly higher in 2019 compared to 2018. Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Consolidated Balance Sheets.

# CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2017 and December 31, 2018 include:

| millions of Canadian dollars | Increase (Decrease) | Explanation |
|---|---|---|
| **Assets** | | |
| Cash and cash equivalents | **$ (122)** | Decreased due to additions of property, plant, and equipment and payment of common dividend. These were partially offset by increased cash from operations, changes in borrowings and the issuance of preferred shares. |
| Inventory | **56** | Increased due to the effect of a stronger USD on the translation of Emera’s foreign subsidiaries and increased fuel inventory as a result of higher volumes and higher commodity pricing at NSPI. |
| Derivative instruments (current and long-term) | **(86)** | Decreased due to settlements of derivative instruments and lower commodity prices at NSPI. |
| Regulatory assets (current and long-term) | **158** | Increased due to the effect of a stronger USD on the translation of foreign subsidiaries, increased fuel clauses at Tampa Electric and increased deferred income tax regulatory asset at NSPI, partially offset by decreased storm reserve at Tampa Electric. |
| Assets held for sale (current and long-term), net of liabilities | **810** | Increased due to the pending sale of the NEGG facilities. |
| Property, plant and equipment, net of accumulated depreciation and amortization | **1,717** | Increased due to additions at regulated utilities, and the effect of a stronger USD on the translation of Emera's foreign subsidiaries, partially offset by the reclassification of NEGG facilities to assets held for sale and increased accumulated depreciation. |
| Investments subject to significant influence | **101** | Increased due to investment in LIL and NSPML. |
| Goodwill | **508** | Increased due to the effect of a stronger USD on the translation of Emera’s foreign subsidiaries. |
| Receivables and other assets (current and long-term) | **324** | Increased primarily due to reclassification of alternative minimum tax credit carryforwards from deferred income tax liabilities at Emera Florida and New Mexico and higher gas transportation assets at Emera Energy. |
| **Liabilities and Equity** | | |
| Short-term debt and long-term debt (including current portion) | **1,475** | Increased due to the effect of a stronger USD on foreign currency debt, increased borrowings under existing credit facilities, and increased borrowings of long-term debt at Emera Florida and New Mexico. |
| Accounts payable | **128** | Increased due to the effect of a stronger USD on the translation of foreign subsidiaries and higher commodity volumes and prices at EES. |
| Deferred income tax liabilities, net of deferred income tax assets | **260** | Increased due to tax deductions in excess of accounting depreciation related to property, plant and equipment, reclassification of alternative minimum tax credit carryforwards to receivables and other current assets at Emera Florida and New Mexico, and net utilization of tax loss carryforwards, partially offset by increased income tax credits primarily related to solar projects at Tampa Electric. |
| Derivative instruments (current and long-term) | **55** | Increased due to the effect of a stronger USD on the translation of Emera’s foreign subsidiaries and new contracts at Emera Energy, partially offset by the reversal of 2017 asset management agreement mark-to-market losses. |
| Regulatory liabilities (current and long-term) | **142** | Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries and replenishment of the storm reserve at Tampa Electric, partially offset by increased deferrals related to derivative instruments at NSPI. |

| | | |
|---|---|---|
| Pension and post-retirement liabilities | **82** | Increased due to a decrease in fair value of plan assets at Emera Florida and New Mexico and the effect of a stronger USD on the translation of Emera's foreign subsidiaries. |
| Other liabilities (current and long-term) | **155** | Increased due to investment tax credits primarily related to solar projects at Tampa Electric and the effect of a stronger USD on the translation of Emera's foreign subsidiaries. |
| Common stock | **215** | Increased due to the dividend reinvestment plan and issuance of common stock for the purchase of additional shares of ICDU. |
| Cumulative preferred stock | **295** | Increased due to the issuance of preferred shares. |
| Accumulated other comprehensive income | **503** | Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries. |
| Retained earnings | **184** | Increased due to net income in excess of dividends paid. |
| Non-controlling interest in subsidiaries | **(51)** | Decreased due to increased ownership in GBPC. |

# DEVELOPMENTS

**Pending Sale of Emera Energy's New England Gas Generating Facilities**

On November 26, 2018, Emera announced an agreement to sell its three NEGG facilities for $590 million USD plus a final working capital adjustment made on close. Proceeds from the sale of the NEGG facilities will be used to reduce corporate level debt and support capital investment opportunities within the regulated utility business. The transaction is expected to close in the first quarter of 2019 and is subject to certain regulatory approvals including approval of the FERC. The applicable provisions of the *Hart-Scott-Rodino Antitrust Act* have been satisfied.

**Increase in Common Dividend**

Effective August 9, 2018, Emera's Board of Directors approved an increase in the annual common share dividend rate from $2.26 to $2.35. The first quarterly dividend payment at the increased rate was paid on November 15, 2018.

**USGAAP Reporting Extension**

On January 26, 2018, Emera was granted exemptive relief by Canadian securities regulators allowing Emera to continue to report its financial results in accordance with USGAAP (the "Exemptive Relief"). On July 18, 2018, Emera was granted an order pursuant to the *Companies Act* (Nova Scotia) exempting Emera from the *Companies Act* requirement to prepare its annual financial statements in accordance with International Financial Reporting Standards ("IFRS") (the "Companies Act Relief"). Both the Exemptive Relief and the Companies Act Relief will remain in effect until the earlier of: (i) January 1, 2024; (ii) the first day of the Company's financial year commencing after the Company ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities. The Exemptive Relief and the Companies Act Relief each replace similar exemptive relief that had been previously granted to Emera in 2014 and would have expired by January 1, 2019.

### Preferred Shares

On May 31, 2018, Emera issued 12 million Cumulative Minimum Rate Reset First Preferred Shares, Series H at $25.00 per share at an initial dividend rate of 4.9 per cent. The aggregate gross and net proceeds from the offering were $300 million and $295 million, respectively. The net proceeds of the preferred share offering were used for general corporate purposes.

On July 6, 2018, Emera announced it would not redeem the 10,000,000 Cumulative Rate Reset First Preferred Shares, Series C Shares. The holders of the Series C Shares had the right, at their option, to convert all or any of their Series C Shares, on a one-for-one basis, into Cumulative Floating Rate First Preferred Shares, Series D of the Company on August 15, 2018 or to continue to hold their Series C Shares. On August 8, 2018, Emera announced that, after having taken into account all conversion notices received from holders, no First Preferred Shares, Series C Shares would be converted into Cumulative Floating Rate First Preferred Shares, Series D Shares.

### Tampa Electric Big Bend Power Station Modernization

On May 24, 2018, Tampa Electric announced its intention to invest approximately $850 million USD to modernize the Big Bend Power Station. This modernization project includes conversion of Unit 1 from coal-fired to natural gas combined-cycle technology and the early retirement of Unit 2. This project has been initiated and is expected to be complete in 2023.

### Tampa Electric Tax Reform and Storm Settlement

On March 1, 2018, the FPSC approved a settlement agreement filed by Tampa Electric that authorizes the utility to net the estimated amount of storm cost recovery against the return of estimated 2018 tax reform benefits to customers. Refer to the “Business Overview and Outlook - Emera Florida and New Mexico”, and “Financial Highlights - Emera Florida and New Mexico” sections for further details.

### NSPML

The Maritime Link entered service on January 15, 2018, enabling the transmission of electricity between Newfoundland and Nova Scotia. In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI. Prior to Q1 2018, NSPML recorded non-cash AFUDC earnings as it was under construction. Refer to the “Business Overview and Outlook - Corporate and Other - ENL” section for further details.

## Appointments

### Board of Directors

Effective July 10, 2018, James V. Bertram joined the Emera Board of Directors. Mr. Bertram is currently Chair of the Board, and former President and Chief Executive Officer, of Keyera Corporation, a publicly-traded, midstream oil and gas operator based in Calgary, Alberta.

Effective July 10, 2018, Jochen E. Tilk joined the Emera Board of Directors. Mr. Tilk is the former Executive Chair of Nutrien Inc., a Canadian global supplier of agricultural products and services based in Saskatoon, Saskatchewan. He is the former President and Chief Executive Officer of Potash Corporation of Saskatchewan.

# OUTSTANDING COMMON STOCK DATA

| **Common stock**<br>**Issued and outstanding:** | millions of shares | millions of Canadian dollars |
|---|---|---|
| Balance, December 31, 2016 | 210.02 | $ 4,738 |
| Conversion of Convertible Debentures | 0.15 | 6 |
| Issuance of common stock | 14.61 | 680 |
| Issued under Purchase Plans at market rate | 3.89 | 182 |
| Discount on shares purchased under Dividend Reinvestment Plan | - | (9) |
| Options exercised under senior management stock option plan | 0.10 | 3 |
| Employee Share Purchase Plan | - | 1 |
| Balance, December 31, 2017 | 228.77 | $ 5,601 |
| Conversion of Convertible Debentures | 0.01 | - |
| Issuance of common stock (1) | 0.45 | 22 |
| Issued under Purchase Plans at market rate | 4.87 | 200 |
| Discount on shares purchased under Dividend Reinvestment Plan | - | (9) |
| Options exercised under senior management stock option plan | 0.02 | 1 |
| Employee Share Purchase Plan | - | 1 |
| **Balance, December 31, 2018** | **234.12** | **$ 5,816** |

(1) In Q1 2018, Emera issued 0.45 million common shares to facilitate the creation and issuance of 1.8 million depository receipts in connection with the ICDU share acquisition. The depository receipts are listed on the Bahamas International Securities Exchange.

As at February 12, 2019, the amount of issued and outstanding common shares was 234.2 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, 2018 was 234.9 million (2017 – 215.3 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2018 was 233.0 million (2017 – 213.4 million).

# FINANCIAL HIGHLIGHTS

## Emera Florida and New Mexico

All amounts are reported in USD, unless otherwise stated.

| For the<br>millions of US dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| Operating revenues – regulated electric | $ **499** | $ 470 | $ **2,059** | $ 2,048 |
| Operating revenues – regulated gas | **211** | 206 | **764** | 732 |
| Operating revenues – non-regulated | **3** | 4 | **13** | 13 |
| Total operating revenues | **713** | 680 | **2,836** | 2,793 |
| Regulated fuel for generation and purchased power | **145** | 143 | **610** | 634 |
| Regulated cost of natural gas | **91** | 84 | **300** | 292 |
| Adjusted contribution to consolidated net income – USD | $ **77** | $ 63 | $ **331** | $ 295 |
| Adjusted contribution to consolidated net income – CAD | $ **101** | $ 80 | $ **428** | $ 382 |
| Revaluation of US non-regulated deferred income taxes | $ **-** | $ (221) | $ **-** | $ (221) |
| Contribution to consolidated net income – USD | $ **77** | $ (158) | $ **331** | $ 74 |
| Contribution to consolidated net income – CAD | $ **101** | $ (203) | $ **428** | $ 99 |
| Adjusted contribution to consolidated earnings per common share – CAD | $ **0.43** | $ 0.37 | $ **1.84** | $ 1.79 |
| Contribution to consolidated earnings per common share – CAD | $ **0.43** | $ (0.94) | $ **1.84** | $ 0.46 |
| Net income weighted average foreign exchange rate – CAD/USD | $ **1.31** | $ 1.28 | $ **1.29** | $ 1.34 |
| | | | | |
| EBITDA – USD | $ **244** | $ 252 | $ **998** | $ 1,060 |
| EBITDA – CAD | $ **322** | $ 320 | $ **1,293** | $ 1,374 |

## 2017 Revaluation of US Non-regulated Deferred Income Taxes

In Q4 2017, due to enactment of the *US Tax Cuts and Jobs Act of 2017*, Emera Florida and New Mexico recorded a $221 million USD non-cash income tax expense resulting from the provisional revaluation of existing US non-regulated net deferred income tax assets. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. Management believes excluding this revaluation from adjusted net income better distinguishes the ongoing operations of the business, and allows investors to better understand and evaluate the Company.

## Net Income

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 – 2017** | **$ (158)** | **$ 74** |
| Increased electric operating revenues - see Operating Revenues - Regulated Electric below | 29 | 11 |
| Increased gas operating revenues - see Operating Revenues - Regulated Gas below | 5 | 32 |
| (Increased) decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below | (2) | 24 |
| Increased cost of natural gas sold - see Regulated Cost of Natural Gas below | (7) | (8) |
| Increased OM&G expenses due to Tampa Electric's regulatory agreement to net storm costs and 2018 tax reform benefits resulting in storm costs recorded through OM&G, with the offsetting tax reform benefits recorded in income tax expense | (31) | (116) |
| Increased depreciation and amortization due to asset growth and PGS's regulatory agreement to net amortization of its MGP environmental regulatory asset and 2018 tax reform benefits. The offsetting tax reform benefits were recorded through income tax expense | (6) | (27) |
| Increased other income as the result of higher AFUDC earnings due to the construction of the first tranche of solar and the Big Bend modernization project | 1 | 6 |
| Decreased income tax expense due to the reduction of the US federal corporate income tax rate, the amortization of deferred income tax regulatory liabilities and decreased income before provision for income taxes. A portion of this benefit is offset by the additional OM&G and amortization costs discussed above | 27 | 112 |
| Revaluation of US non-regulated deferred income taxes in 2017 due to tax reform | 221 | 221 |
| Other | (2) | 2 |
| **Contribution to consolidated net income – 2018** | **$ 77** | **$ 331** |

Emera Florida and New Mexico’s CAD adjusted contribution to consolidated net income increased by $21 million to $101 million in Q4 2018, from $80 million in Q4 2017. For the year ended December 31, 2018, Emera Florida and New Mexico’s CAD adjusted contribution to consolidated net income increased $46 million to $428 million, from $382 million in 2017. These increases were primarily due to higher revenues as the result of customer growth, favourable weather in Florida and higher AFUDC earnings as a result of the completion of the first tranche of solar projects and the Big Bend modernization project at Tampa Electric.

The impact of the change in the foreign exchange rate increased CAD earnings for the quarter and year ended December 31, 2018, by $4 million and $1 million, respectively.

Emera Florida and New Mexico's adjusted contribution to consolidated net income by area is summarized in the following table:

| For the<br>millions of US dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| Tampa Electric | **$ 64** | $ 57 | **$ 294** | $ 274 |
| PGS | **11** | 12 | **47** | 43 |
| NMGC | **11** | 10 | **25** | 22 |
| Other (1) | **(9)** | (16) | **(35)** | (44) |
| **Adjusted contribution to consolidated net income** | **$ 77** | $ 63 | **$ 331** | $ 295 |

(1) Other includes TECO Finance and administration costs.

## Operating Revenues – Regulated Electric

Electric revenues increased $29 million to $499 million in Q4 2018, compared to $470 million in Q4 2017. For the year ended December 31, 2018, electric revenues increased $11 million to $2,059 million, from $2,048 million in 2017. Changes in both periods were primarily due to customer growth, favourable weather and higher rates related to the completion of the first tranche of solar projects. The year-over-year increase included an additional benefit to rates due to the completion of the Polk Power Station expansion.

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

**Q4 Electric Revenues**

millions of US dollars

| | **2018** | 2017 |
|---|---|---|
| Residential | **$ 265** | $ 237 |
| Commercial | **147** | 139 |
| Industrial | **40** | 39 |
| Other (1) | **47** | 55 |
| Total | **$ 499** | $ 470 |

(1) Other includes sales to public authorities, off-system sales to other utilities and regulatory deferrals related to clauses.

**Annual Electric Revenues**

millions of US dollars

| | **2018** | 2017 |
|---|---|---|
| Residential | **$ 1,067** | $ 1,006 |
| Commercial | **582** | 578 |
| Industrial | **161** | 158 |
| Other (1) | **249** | 306 |
| Total | **$ 2,059** | $ 2,048 |

(1) Other includes sales to public authorities, off-system sales to other utilities and regulatory deferrals related to clauses.

**Q4 Electric Sales Volumes**

Gigawatt hours ("GWh")

| | **2018** | 2017 |
|---|---|---|
| Residential | **2,320** | 2,113 |
| Commercial | **1,568** | 1,503 |
| Industrial | **490** | 495 |
| Other | **486** | 489 |
| Total | **4,864** | 4,600 |

**Annual Electric Sales Volumes**

GWh

| | **2018** | 2017 |
|---|---|---|
| Residential | **9,418** | 9,029 |
| Commercial | **6,266** | 6,362 |
| Industrial | **2,014** | 2,024 |
| Other | **2,219** | 2,010 |
| Total | **19,917** | 19,425 |

## Operating Revenues – Regulated Gas

Gas revenues increased $5 million to $211 million in Q4 2018, compared to $206 million in Q4 2017. For the year ended December 31, 2018, gas revenues increased $32 million to $764 million, from $732 million in 2017, due to higher clause recoveries, customer growth in Florida and favourable weather in Florida and New Mexico. This was partially offset by lower commodity costs in New Mexico.

Gas revenues and sales volumes are summarized in the following tables by customer class:

**Q4 Gas Revenues**
millions of US dollars

| | 2018 | 2017 |
|---|---|---|
| Residential | **$ 116** | $ 110 |
| Commercial | **61** | 60 |
| Industrial (1) | **9** | 9 |
| Other (2) | **25** | 27 |
| Total | **$ 211** | $ 206 |

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.

**Annual Gas Revenues**
millions of US dollars

| | 2018 | 2017 |
|---|---|---|
| Residential | **$ 381** | $ 367 |
| Commercial | **226** | 220 |
| Industrial (1) | **37** | 35 |
| Other (2) | **120** | 110 |
| Total | **$ 764** | $ 732 |

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.

**Q4 Gas Sales Volumes**
Therms (millions)

| | 2018 | 2017 |
|---|---|---|
| Residential | **141** | 113 |
| Commercial | **214** | 202 |
| Industrial | **339** | 292 |
| Other | **72** | 53 |
| Total | **766** | 660 |

**Annual Gas Sales Volumes**
Therms (millions)

| | 2018 | 2017 |
|---|---|---|
| Residential | **389** | 344 |
| Commercial | **795** | 754 |
| Industrial | **1,338** | 1,216 |
| Other | **269** | 245 |
| Total | **2,791** | 2,559 |

## Regulated Fuel for Generation, Purchased Power and Cost of Natural Gas

### Electric Capacity

Tampa Electric is required to maintain a generating capacity greater than firm peak demand. The total Tampa Electric-owned generation capacity is 5,238 MW. Tampa Electric meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

### Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $2 million to $145 million in Q4 2018, compared to $143 million in Q4 2017. For the year ended December 31, 2018, regulated fuel for generation and purchased power decreased $24 million to $610 million, compared to $634 million in 2017 primarily due to a change in generation mix to lower-cost natural gas and solar, from coal, oil and petcoke.

**Q4 Production Volumes**
GWh

| | 2018 | 2017 |
|---|---|---|
| Natural gas | **4,160** | 3,365 |
| Coal | **430** | 905 |
| Oil and petcoke | **-** | 228 |
| Solar | **68** | 9 |
| Purchased power | **495** | 171 |
| Total production volumes | **5,153** | 4,678 |

**Annual Production**
GWh

| | 2018 | 2017 |
|---|---|---|
| Natural gas | **16,097** | 13,685 |
| Coal | **3,088** | 5,089 |
| Oil and petcoke | **472** | 924 |
| Solar | **118** | 45 |
| Purchased power | **1,222** | 559 |
| Total production volumes | **20,997** | 20,302 |

**Q4 Average Fuel Costs**

| US dollars | 2018 | 2017 |
|---|---|---|
| Dollars per Megawatt hour ("MWh") | **$ 28** | $ 31 |

**Annual Average Fuel Costs**

| US dollars | 2018 | 2017 |
|---|---|---|
| Dollars per MWh | **$ 29** | $ 31 |

Tampa Electric's fuel costs are affected by commodity prices and generation mix that is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on stream first (renewable energy from solar), such that the incremental cost of production increases as sales volumes increase. Generation mix may also be affected by plant outages, plant performance, availability of lower priced short-term purchased power, availability of renewable solar generation, and compliance with environmental standards and regulations.

**Regulated Cost of Natural Gas**

PGS and NMGC purchase gas from various suppliers depending on the needs of their customers. In Florida, gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has firm transportation capacity for delivery by PGS to its customers. NMGC's natural gas is transported on major interstate pipelines and NMGC's intrastate transmission system to customers.

In Florida, natural gas service is unbundled for non-residential customers and residential customers who use more than 1,999 therms annually and elect the option. In New Mexico, NMGC is required to provide transportation-only services for all customer classes if requested. Because the commodity portion of bundled sales is included in operating revenues, at the cost of the gas on a pass-through basis, there is no net earnings effect when a customer shifts to transportation-only sales.

Regulated cost of natural gas increased $7 million to $91 million in Q4 2018, compared to $84 million in Q4 2017. For the year ended December 31, 2018, regulated cost of natural gas increased $8 million to $300 million, compared to $292 million in 2017. The increases were primarily due to higher sales volumes in Florida and New Mexico and higher commodity costs in Florida partially offset by lower commodity costs in New Mexico.

Gas sales by type are summarized in the following tables:

**Q4 Gas Sales Volumes by Type**
Therms (millions)

| | **2018** | 2017 |
|---|---|---|
| System Supply | **242** | 194 |
| Transportation | **524** | 466 |
| Total | **766** | 660 |

**Annual Gas Sales Volumes by Type**
Therms (millions)

| | **2018** | 2017 |
|---|---|---|
| System Supply | **745** | 671 |
| Transportation | **2,046** | 1,888 |
| Total | **2,791** | 2,559 |

Gas sales volumes increased for the quarter and year ended December 31, 2018, primarily due to customer growth in Florida and favourable winter weather in Florida and New Mexico.

## Regulatory Recovery Mechanisms

**Tampa Electric**

*Fuel Recovery Clause*
Tampa Electric has a fuel recovery clause approved by the FPSC, allowing it the opportunity to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a fuel clause regulatory asset or liability and recovered from or returned to customers in a subsequent year.

*Other Cost Recovery Clauses*
The FPSC annually approves cost-recovery rates for purchased power, capacity, environmental and conservation costs including a return on capital invested. Differences between the prudently incurred clause-recoverable costs and amounts recovered from customers through electricity rates in a year are deferred to a corresponding regulatory asset or liability and recovered from or returned to customers in a subsequent year.

*Storm Reserve*
The storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric's system. Tampa Electric can petition the FPSC to seek recovery of restoration costs over a 12-month period, or longer, as determined by the FPSC, as well as replenish the reserve.

**PGS**

*Fuel Recovery Clause*
PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its purchased gas adjustment ("PGA") clause. This clause is designed to recover actual costs incurred by PGS for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers. These charges may be adjusted monthly based on a cap approved annually by the FPSC.

*Other Cost Recovery Clauses*
The FPSC annually approves cost-recovery rates for conservation costs including a return on capital invested incurred in developing and implementing energy conservation programs. PGS has a Cast Iron/Bare Steel Pipe Replacement clause to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. The FPSC approved a replacement program at a cost of approximately $80 million USD over a 10-year period. As part of the depreciation study settlement agreement approved by the FPSC in February 2017, the Cast Iron/Bare Steel clause was expanded to allow recovery of accelerated replacement of certain obsolete pipe.

**NMGC**

*Fuel Recovery Clause*
NMGC recovers gas supply costs through a purchased gas adjustment clause ("PGAC"). This clause recovers NMGC's actual costs for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers.

On a monthly basis, NMGC can adjust the charges based on next month's expected cost of gas and any prior month under-recovery or over-recovery. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that the continued use of the PGAC is reasonable and necessary. In December 2016, NMGC received approval of its PGAC Continuation Filing for the four-year period ending December 2020.

# NSPI

| For the<br>millions of Canadian dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| Operating revenues – regulated electric | **$ 385** | $ 355 | **$ 1,440** | $ 1,338 |
| Regulated fuel for generation and purchased power (1) | **179** | 141 | **639** | 477 |
| Contribution to consolidated net income | **$ 28** | $ 23 | **$ 131** | $ 129 |
| Contribution to consolidated earnings per common share - basic | **$ 0.12** | $ 0.11 | **$ 0.56** | $ 0.60 |
| | | | | |
| EBITDA | **$ 126** | $ 104 | **$ 498** | $ 466 |

(1) Regulated fuel for generation and purchased power includes NSPI's FAM and fixed cost deferrals on the Consolidated Income Statement, however it is excluded in the segment overview. The amounts excluded were $(19) million in Q4 2018 (2017 - $16 million) and $(46) million for the year ended December 31, 2018 (2017 - $59 million).

## Net Income

Highlights of the net income changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2017** | **$ 23** | **$ 129** |
| Increased operating revenues - see Operating Revenues - Regulated Electric below | 30 | 102 |
| Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below | (38) | (162) |
| Decreased FAM and fixed cost deferrals due to a current year total under-recovery of fuel costs, compared to the prior year total over-recovery of fuel costs and the lower application of non-fuel revenues. Year-over-year was partially offset by the 2017 refund to customers of 2016 fuel costs | 35 | 105 |
| Increased OM&G expenses in 2018 primarily due to storm costs | (7) | (19) |
| Increased depreciation and amortization due to increased property, plant and equipment | (4) | (12) |
| Increased interest expense, net, year-over-year primarily due to higher average interest rate on the revolving credit facility and higher interest on the FAM regulatory deferral | (4) | (9) |
| Increased income tax expense primarily due to change in tax reserve | (8) | (8) |
| Other | 1 | 5 |
| **Contribution to consolidated net income – 2018** | **$ 28** | **$ 131** |

NSPI’s contribution to consolidated net income increased $5 million to $28 million in Q4 2018 from $23 million in Q4 2017. For the year ended December 31, 2018, NSPI’s contribution to consolidated net income increased $2 million to $131 million from $129 million in 2017. These increases were the result of increased sales volume due to load growth and weather and decreased FAM and fixed cost deferral expense. This was partially offset by increased depreciation and amortization, OM&G and interest expenses.

## Operating Revenues – Regulated Electric

Operating revenues increased $30 million to $385 million in Q4 2018, compared to $355 million in Q4 2017. Revenues increased as a result increased sales volumes due to load growth and weather.

For the year ended December 31, 2018, operating revenues increased $102 million to $1,440 million, compared to $1,338 million in 2017. Revenues increased due to increased sales volume due to load growth and weather, the refund to customers of prior year over-recovery of fuel costs in 2017, and increased fuel related electricity pricing in 2018. This was partially offset by the Maritime Link assessment.

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

**Q4 Electric Revenues**
millions of Canadian dollars

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Residential | $ | **199** | $ | 178 |
| Commercial | | **107** | | 101 |
| Industrial | | **62** | | 56 |
| Other | | **10** | | 13 |
| Total | $ | **378** | $ | 348 |

**Annual Electric Revenues**
millions of Canadian dollars

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Residential | $ | **731** | $ | 679 |
| Commercial | | **405** | | 387 |
| Industrial | | **233** | | 200 |
| Other | | **43** | | 43 |
| Total | $ | **1,412** | $ | 1,309 |

**Q4 Electric Sales Volumes**
GWh

| | 2018 | 2017 |
|---|---|---|
| Residential | **1,259** | 1,120 |
| Commercial | **799** | 771 |
| Industrial | **669** | 637 |
| Other | **76** | 85 |
| Total | **2,803** | 2,613 |

**Annual Electric Sales Volumes**
GWh

| | 2018 | 2017 |
|---|---|---|
| Residential | **4,581** | 4,374 |
| Commercial | **3,102** | 3,060 |
| Industrial | **2,611** | 2,466 |
| Other | **323** | 345 |
| Total | **10,617** | 10,245 |

## Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $38 million to $179 million in Q4 2018, compared to $141 million in Q4 2017. For the year ended December 31, 2018, regulated fuel for generation and purchased fuel power increased $162 million to $639 million, compared to $477 million in 2017. Changes in both periods were primarily due to the payment of the Maritime Link assessment, increased commodity prices, and increased sales volume.

NSPI's FAM regulatory liability balance decreased $16 million from $177 million at December 31, 2017 to $161 million at December 31, 2018 primarily due to the net under-recovery of current period fuel costs and the refund to customers of the 2017 Maritime Link assessment. This was partially offset by the recovery in 2018 of the Maritime Link assessment to be refunded to customers as part of the assessment decision.

**Q4 Production Volumes**

GWh

| | 2018 | 2017 |
|---|---|---|
| Coal | **1,466** | 1,168 |
| Natural gas | **275** | 349 |
| Oil and petcoke | **254** | 352 |
| Purchased power – other | **175** | 220 |
| Total non-renewables | **2,170** | 2,089 |
| Purchased power – IPP | **369** | 374 |
| Wind and hydro – renewables | **318** | 190 |
| Purchased power – Community Feed-in Tariff program ("COMFIT") | **153** | 158 |
| Biomass – renewables | **60** | 53 |
| Total renewables | **900** | 775 |
| Total production volumes | **3,070** | 2,864 |

**Annual Production Volumes**

GWh

| | 2018 | 2017 |
|---|---|---|
| Coal | **4,930** | 4,839 |
| Natural gas | **1,427** | 1,444 |
| Oil and petcoke | **1,246** | 1,169 |
| Purchased power – other | **540** | 481 |
| Total non-renewables | **8,143** | 7,933 |
| Purchased power – IPP | **1,275** | 1,246 |
| Wind and hydro – renewables | **1,202** | 1,121 |
| Purchased power – COMFIT | **553** | 525 |
| Biomass – renewables | **189** | 153 |
| Total renewables | **3,219** | 3,045 |
| Total production volumes | **11,362** | 10,978 |

**Q4 Average Fuel Costs**

| | 2018 | 2017 |
|---|---|---|
| Dollars per MWh | **$ 58** | $ 49 |

**Annual Average Fuel Costs**

| | 2018 | 2017 |
|---|---|---|
| Dollars per MWh | **$ 56** | $ 43 |

Average fuel cost per MWh increased in Q4 2018 and for the year ended December 31, 2018, compared to 2017, due to payment of the Maritime Link assessment and increased 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 IPPs including COMFIT participants, for which NSPI has PPAs in place. This results in the incremental cost of production generally increasing 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.

NSPI-owned hydro and wind have no fuel cost component. After hydro and wind, historically, petcoke and coal have the lowest per unit fuel cost, followed by natural gas. Oil, biomass and purchased power have the next lowest fuel cost, depending on the relative pricing of each.

The generation mix has transformed with the addition of new non-dispatchable renewable energy sources such as wind, including IPP and COMFIT, which typically have a higher cost per MWh than NSPI-owned generation or other purchased power sources.

## Regulatory Recovery Mechanisms

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

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors.

NSPI has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel costs from customers through annual fuel rate adjustments. Differences between prudently incurred 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.

# Emera Maine

All amounts are reported in USD, unless otherwise stated.

| For the<br>millions of US dollars (except per share amounts) | Three months ended<br>December 31 | | | | For the year ended<br>December 31 | | | |
|---|---|---|---|---|---|---|---|---|
| | | **2018** | | 2017 | | **2018** | | 2017 |
| Operating revenues – regulated electric | **$** | **50** | $ | 55 | **$** | **214** | $ | 228 |
| Regulated fuel for generation and purchased power (1) | | **10** | | 17 | | **42** | | 64 |
| Contribution to consolidated net income – USD | **$** | **9** | $ | 7 | **$** | **34** | $ | 36 |
| Contribution to consolidated net income – CAD | **$** | **11** | $ | 8 | **$** | **44** | $ | 46 |
| Contribution to consolidated earnings per common share – basic – CAD | **$** | **0.05** | $ | 0.04 | **$** | **0.19** | $ | 0.22 |
| Net income weighted average foreign exchange rate – CAD/USD | **$** | **1.32** | $ | 1.27 | **$** | **1.30** | $ | 1.30 |
| | | | | | | | | |
| EBITDA – USD | **$** | **25** | $ | 23 | **$** | **107** | $ | 107 |
| EBITDA – CAD | **$** | **33** | $ | 29 | **$** | **139** | $ | 139 |

(1) Regulated fuel for generation and purchased power includes transmission pool expenses.

## Net Income

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 – 2017** | **$** | **7** | **$** | **36** |
| Decreased operating revenues – see Operating Revenues – Regulated Electric section below | | (5) | | (14) |
| Decreased regulated fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power section below | | 7 | | 22 |
| Increased OM&G primarily due to increased storm restoration work, higher medical costs, and regulatory adjustments related to the distribution rate case, partially offset by higher capitalized construction overheads in 2018 | | - | | (8) |
| Increased depreciation and amortization primarily due to increased regulatory amortization as a result of reduced purchase power contracts and higher plant in service | | (2) | | (14) |
| Decreased income tax expense primarily due to the reduction of the US federal corporate income tax rate and decreased income before provision for income taxes | | 2 | | 13 |
| Other | | - | | (1) |
| **Contribution to consolidated net income – 2018** | **$** | **9** | **$** | **34** |

Emera Maine's CAD contribution to consolidated net income increased by $3 million to $11 million in Q4 2018, from $8 million in Q4 2017. For the year ended December 31, 2018, Emera Maine's CAD contribution to consolidated net income decreased $2 million to $44 million, from $46 million in 2017. The foreign exchange rate had minimal impact for the quarter and year ended December 31, 2018.

## Operating Revenues – Regulated Electric

Operating revenues decreased $5 million to $50 million in Q4 2018, compared to $55 million in Q4 2017. For the year ended December 31, 2018, operating revenues decreased $14 million to $214 million in 2018, from $228 million in 2017. The year-over-year decrease was due to reduced transmission pool revenue primarily as a result of lower rates and lower stranded cost revenue primarily due to the expiration of a major purchased power contract. These decreases were partially offset by increased load due to favourable summer weather.

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

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

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Electric revenues | **$** | **41** | $ | 41 |
| Transmission pool revenues | | **8** | | 10 |
| Resale of purchased power | | **1** | | 4 |
| Operating revenues – regulated electric | **$** | **50** | $ | 55 |

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

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Electric revenues | **$** | **165** | $ | 169 |
| Transmission pool revenues | | **41** | | 48 |
| Resale of purchased power | | **8** | | 11 |
| Operating revenues – regulated electric | **$** | **214** | $ | 228 |

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

**Q4 Electric Revenues**
millions of US dollars

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Residential | **$** | **23** | $ | 21 |
| Commercial | | **16** | | 16 |
| Industrial | | **3** | | 2 |
| Other (1) | | **(1)** | | 2 |
| Total | **$** | **41** | $ | 41 |

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

**Annual Electric Revenues**
millions of US dollars

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Residential | **$** | **83** | $ | 81 |
| Commercial | | **62** | | 62 |
| Industrial | | **12** | | 12 |
| Other (1) | | **8** | | 14 |
| Total | **$** | **165** | $ | 169 |

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

**Q4 Electric Sales Volumes**
GWh

| | 2018 | 2017 |
|---|---|---|
| Residential | **218** | 207 |
| Commercial | **192** | 194 |
| Industrial | **89** | 87 |
| Other | **3** | 3 |
| Total | **502** | 491 |

**Annual Electric Sales Volumes**
GWh

| | 2018 | 2017 |
|---|---|---|
| Residential | **827** | 802 |
| Commercial | **769** | 773 |
| Industrial | **354** | 349 |
| Other | **12** | 14 |
| Total | **1,962** | 1,938 |

## Regulated Fuel for Generation and Purchased Power

Emera Maine’s regulated fuel for generation and purchased power decreased $7 million to $10 million in Q4 2018, compared to $17 million in Q4 2017. For the year ended December 31, 2018 regulated fuel for generation and purchased power decreased $22 million to $42 million, from $64 million in 2017 due to the expiration of a major purchased power contract.

## 2017 Revaluation of US Regulated Deferred Income Taxes

In Q4 2017, due to enactment of the *US Tax Cuts and Jobs Act of 2017* Emera Maine recorded a $112 million USD non-cash provisional revaluation of existing US regulated net deferred income tax liabilities. Emera Maine recorded an equivalent increase of a regulatory liability as the impact of lower US taxes is expected to be returned to customers over time, as required by the Act or by order of the regulator. As a result, the deferred tax adjustment for Emera Maine had an impact on the 2017 balance sheet but no impact on 2017 earnings. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation.

## Regulatory Recovery Mechanisms

Emera Maine's distribution operations and stranded cost recoveries are regulated by the MPUC. The transmission operations are regulated by the FERC. Rates for these three elements are established in distinct regulatory proceedings.

Emera Maine's distribution businesses operate under a traditional cost-of-service regulatory structure, and distribution rates are set by the MPUC. For stranded cost recoveries, Emera Maine is 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. Emera Maine's transmission businesses operate based on formulas utilizing prior year actual transmission investments and operating costs. Emera Maine collects revenue for its bulk transmission assets from ISO New England. Emera Maine is also required to contribute towards the total cost of the ISO New England pool transmission facilities on a ratable basis according to the proportion of the total New England load that their customers represent.

# Emera Caribbean

All amounts are reported in USD, unless otherwise stated.

| For the<br>millions of US dollars (except per share amounts) | Three months ended<br>December 31 | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| Operating revenues – regulated electric | **$ 90** | $ 84 | **$ 360** | $ 334 |
| Regulated fuel for generation and purchased power | **45** | 41 | **183** | 152 |
| Adjusted contribution to consolidated net income | **$ 11** | $ 1 | **$ 35** | $ 24 |
| Adjusted contribution to consolidated net income – CAD | **$ 14** | $ 1 | **$ 45** | $ 31 |
| After-tax equity securities mark-to-market gain (loss) | **(2)** | - | **(3)** | - |
| Contribution to consolidated net income | **$ 9** | $ 1 | **$ 32** | $ 24 |
| Contribution to consolidated net income – CAD | **$ 12** | $ 1 | **$ 41** | $ 31 |
| Adjusted contribution to consolidated earnings per common share – basic – CAD | **$ 0.06** | $ - | **$ 0.19** | $ 0.15 |
| Contribution to consolidated earnings per common share – basic – CAD | **$ 0.05** | $ - | **$ 0.18** | $ 0.15 |
| Net income weighted average foreign exchange rate – CAD/USD | **$ 1.33** | $ 1.25 | **$ 1.31** | $ 1.30 |
| | | | | |
| Adjusted EBITDA | **$ 22** | $ 11 | **$ 93** | $ 87 |
| Adjusted EBITDA – CAD | **$ 30** | $ 14 | **$ 121** | $ 113 |

## Net Income

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 – 2017** | **$** | **1** | **$** | **24** |
| Increased operating revenues - see Operating Revenues - Regulated Electric below | | 6 | | 26 |
| Increased regulated fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below | | (4) | | (31) |
| Increased other income due to the 2017 impairment charge as a result of damage to Domlec's assets from Hurricane Maria and the recognition of gains on the sale of investment securities in 2018 related to the BLPC self-insurance fund | | 6 | | 6 |
| Decreased OM&G costs due to operational cost savings at GBPC and BLPC quarter-over-quarter. Year-over-year, decreased OM&G due to operational cost savings at GBPC and lower maintenance at Domlec | | 3 | | 5 |
| Other | | (3) | | 2 |
| **Contribution to consolidated net income – 2018** | **$** | **9** | **$** | **32** |

Emera Caribbean's CAD contribution to consolidated net income increased $11 million to $12 million in Q4 2018, compared to $1 million in Q4 2017. For the year ended December 31, 2018, Emera Caribbean's CAD contribution to consolidated net income increased $10 million to $41 million in 2018, compared to $31 million in 2017. These increases were primarily due to the impairment charge recognized in 2017, lower 2018 operating costs at GBPC and Domlec and gains on the sale of equity securities in 2018. The foreign exchange rate had minimal impact for the three months and year ended December 31, 2018.

## Operating Revenues – Regulated Electric

Operating revenues increased $6 million to $90 million in Q4 2018, compared to $84 million in Q4 2017. This increase reflected higher sales volumes at Domlec due to the impact of Hurricane Maria in 2017, increased fuel charge as a result of higher fuel prices in 2018 at BLPC and higher sales volumes at GBPC due to continued recovery from Hurricane Matthew.

For the year ended December 31, 2018, operating revenues increased $26 million to $360 million, compared to $334 million in 2017 due to increased fuel charge as a result of higher fuel prices in 2018 at BLPC, partially offset by lower sales volumes at Domlec in 2018 due to the impact of Hurricane Maria.

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

**Q4 Electric Revenues**
millions of US dollars

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Residential | $ | 30 | $ | 27 |
| Commercial | | 52 | | 49 |
| Industrial | | 6 | | 6 |
| Other | | 2 | | 2 |
| Total | $ | 90 | $ | 84 |

**Annual Electric Revenues**
millions of US dollars

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Residential | $ | 119 | $ | 110 |
| Commercial | | 208 | | 191 |
| Industrial | | 23 | | 23 |
| Other | | 7 | | 7 |
| Total | $ | 357 | $ | 331 |

**Q4 Electric Sales Volumes**
GWh

| | 2018 | 2017 |
|---|---|---|
| Residential | 113 | 105 |
| Commercial | 186 | 182 |
| Industrial | 21 | 20 |
| Other | 4 | 4 |
| Total | 324 | 311 |

**Annual Electric Sales Volumes**
GWh

| | 2018 | 2017 |
|---|---|---|
| Residential | 446 | 462 |
| Commercial | 748 | 753 |
| Industrial | 84 | 85 |
| Other | 15 | 17 |
| Total | 1,293 | 1,317 |

## Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $4 million to $45 million in Q4 2018, compared to $41 million in Q4 2017 and for the year ended December 31, 2018, increased $31 million to $183 million compared to $152 million in 2017, primarily due to higher oil prices.

**Q4 Production Volumes**
GWh

| | 2018 | 2017 |
|---|---|---|
| Oil | 335 | 334 |
| Hydro | 7 | 2 |
| Solar | 5 | 5 |
| Purchased Power | 7 | 5 |
| Total | 354 | 346 |

**Annual Production Volumes**
GWh

| | 2018 | 2017 |
|---|---|---|
| Oil | 1,330 | 1,366 |
| Hydro | 24 | 27 |
| Solar | 18 | 18 |
| Purchased Power | 26 | 20 |
| Total | 1,398 | 1,431 |

**Q4 Average Fuel Costs**

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Dollars per MWh | $ | 127 | $ | 119 |

**Annual Average Fuel Costs**

| | | 2018 | | 2017 |
|---|---|---|---|---|
| Dollars per MWh | $ | 131 | $ | 106 |

Average fuel cost per MWh increased for the quarter and year-to-date, compared to 2017, due to higher oil prices.

## Regulatory Recovery Mechanisms

### BLPC

BLPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner. The FTC approves the calculation of the fuel charge, which is adjusted on a monthly basis.

**GBPC**

GBPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner.

As a result of Hurricane Matthew in 2016, a regulatory asset was established to recover associated restoration costs. In addition, in December 2016, the GBPA approved that over a five year period, 2017 to 2021, the all-in rate for electricity (fuel and base rates) will be held at 2016 levels. This is achievable as the company's fuel costs over this period are forecasted to decrease. Fuel costs are managed through a fuel hedging program which allows predictability of these costs. Any over-recovery of fuel costs during this period will be applied to the Hurricane Matthew regulatory asset, until such time as the asset is recovered. Should GBPC recover funds in excess of the Hurricane Matthew regulatory asset, the excess will be placed in a new storm reserve. If the Hurricane Matthew deferral is not fully recovered at the end of five years, GBPC will have the opportunity to request recovery from customers in future rates.

As a component of its regulatory agreement 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 7.8 per cent return on rate base and 50 per cent of amounts above 9.8 per cent return on rate base respectively.

**Domlec**

Substantially all of Domlec fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover prudently incurred fuel costs from customers in a timely manner.

# Emera Energy

| For the<br>millions of Canadian dollars (except per share amounts) | Three months ended<br>December 31 | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| Marketing and trading margin (1) (2) | **$ 42** | $ 24 | **$ 115** | $ 44 |
| Electricity and capacity sales (3) | **132** | 115 | **445** | 345 |
| Total operating revenues – non-regulated | **174** | 139 | **560** | 389 |
| Non-regulated fuel for generation and purchased power (4) | **68** | 65 | **238** | 214 |
| Adjusted contribution to consolidated net income | **$ 44** | $ 26 | **$ 120** | $ 24 |
| Revaluation of US non-regulated deferred income taxes | **$ -** | $ 12 | **$ -** | $ 12 |
| After-tax derivative mark-to-market gain (loss) | **67** | (48) | **45** | 57 |
| Contribution to consolidated net income (loss) | **$ 111** | $ (10) | **$ 165** | $ 93 |
| Adjusted contribution to consolidated earnings per common share – basic | **$ 0.19** | $ 0.12 | **$ 0.52** | $ 0.11 |
| Contribution to consolidated earnings per common share – basic | **$ 0.47** | $ (0.05) | **$ 0.71** | $ 0.44 |
| | | | | |
| Adjusted EBITDA | | | | |
| Emera Energy Services | **$ 33** | $ 20 | **$ 85** | $ 25 |
| Emera Energy Generation | **34** | 34 | **125** | 66 |
| Equity Investment in Bear Swamp | **10** | 7 | **32** | 16 |
| Total | **$ 77** | $ 61 | **$ 242** | $ 107 |

(1) Marketing and trading margin represents Emera Energy Service's purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management services' revenues.
(2) Marketing and trading margin excludes a pre-tax mark-to-market gain of $87 million in Q4 2018 (2017 - $37 million loss) and a gain of $16 million for the year ended December 31, 2018 (2017 - $119 million gain).
(3) Electricity and capacity sales exclude a pre-tax mark-to-market gain of $10 million in Q4 2018 (2017 - $40 million loss) and a gain of $38 million for the year ended December 31, 2018 (2017 - $43 million loss).
(4) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market of nil in Q4 2018 (2017 - $3 million gain) and a gain of $5 million for the year ended December 31, 2018 (2017 - $1 million loss).

## 2017 Revaluation of US Non-regulated Deferred Income Taxes

In Q4 2017, due to enactment of the *US Tax Cuts and Jobs Act of 2017*, Emera Energy recorded a $12 million non-cash income tax recovery resulting from the provisional revaluation of existing US non-regulated net deferred income tax liabilities. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. Management believes excluding this revaluation from adjusted net income better distinguishes the ongoing operations of the business, and allows investors to better understand and evaluate the Company.

## Mark-to-Market Adjustments

Emera Energy's "Marketing and trading margin", "Electricity and capacity sales", "Non-regulated fuel for generation and purchased power", "Income from equity investments" and "Income tax expense (recovery)" are affected by MTM adjustments. Management believes excluding the effect of MTM valuations, and changes thereto, from income until settlement better matches the financial effect of these contracts with the underlying cash flows. Variance explanations of the MTM changes for this quarter and for the year are explained in the chart below.

Emera Energy has a number of asset management agreements ("AMA") with counterparties, including local gas distribution utilities, power utilities, and natural gas producers in northeastern North America. The AMAs involve Emera Energy buying or selling gas for a specific term, and the corresponding release of the counterparties' gas transportation/storage capacity to Emera Energy. MTM adjustments on these AMAs 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 value of the corresponding gas transportation asset, which is amortized over the term of the AMA contract.

Subsequent changes in gas price differentials, to the extent they are not offset by the accounting amortization of the gas transportation asset, will result in MTM gains or losses recorded in income. MTM adjustments may be substantial during the term of the contract, especially in the winter months of a contract when delivered volumes and market volatility are usually at peak levels. As a contract is realized, and volumes reduce, MTM volatility is expected to decrease. Ultimately, the gas transportation asset and the MTM 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.

## Net Income

Highlights of the net 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 – 2017** | **$ (10)** | **$ 93** |
| Increased marketing and trading margin - see Emera Energy Services below | 18 | 71 |
| Increased electricity and capacity sales - see Emera Energy Generation below | 17 | 100 |
| Increased non-regulated fuel for generation and purchased power - see Emera Energy Generation below | (3) | (24) |
| Increased OM&G expenses due to increased performance-based compensation resulting from the increased marketing and trading margin; and the impact of an unplanned outage at Bridgeport Energy in 2017 that resulted in higher capitalization of maintenance spend compared to 2018 | (11) | (20) |
| Increased income from equity investments mainly due to higher capacity prices at Bear Swamp in 2018 | 4 | 15 |
| Increased income tax expense due to increased income before provision for income taxes, partially offset by the reduction of the US federal corporate income tax rate | (5) | (41) |
| Increased mark-to-market gain, net of tax quarter-over-quarter primarily due to changes in existing contract positions. Year-over-year decreased mark-to-market gain, net of tax due to a larger reversal of mark-to-market losses in 2017 compared to 2018 and change in existing contract positions, partially offset by lower amortization of gas transportation assets in 2018 | 115 | (12) |
| Revaluation of US non-regulated deferred income taxes in 2017 due to tax reform | (12) | (12) |
| Other | (2) | (5) |
| **Contribution to consolidated net income – 2018** | **$ 111** | **$ 165** |

Excluding the change in mark-to-market and the deferred tax revaluation in 2017, Emera Energy's contribution to consolidated net income increased quarter-over-quarter due to the favourable impact of reduced maintenance on key pipelines in Q4 2018 on Emera Energy Services; and increased capacity prices for Emera Energy Generation. The year-over-year increase was also a result of the impact of favourable weather in 2018 on the business overall.

## Emera Energy Services

EES derives revenue and earnings from the wholesale marketing and trading 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. EES purchases and sells physical natural gas and electricity, the related transportation and transmission capacity rights, and provides related energy asset management services. EES is also responsible for commercial management of electricity production and fuel procurement for Emera Energy Generation's fleet. The primary market area for the natural gas and power marketing and trading business is northeastern North America, including the Marcellus and Utica shale supply areas. EES also participates in the US Gulf Coast and Midwest/Central Canadian natural gas markets. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. EES operates in a competitive environment, and the business relies on knowledge of the region's energy markets, understanding of pipeline and transmission infrastructure, a network of counterparty relationships and a focus on customer service. EES 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.

**Marketing and Trading Margin**

Marketing and trading margin increased $18 million to $42 million in Q4 2018, compared to $24 million in Q4 2017, which saw significant pipeline maintenance that reduced margins on hedged capacity.

Marketing and trading margin increased $71 million to $115 million in 2018, compared to $44 million in 2017. In addition to the Q4 2018 explanation above, this increase was due to the favourable impact of cold weather in early 2018 in several key market areas, which resulted in higher market prices and volatility that led to higher margins; and also provided favourable hedging opportunities for the first quarter of 2018. The impact of warmer summer weather in 2018 compared to 2017, also contributed to the increase.

## Emera Energy Generation

Emera Energy wholly owns and operates a portfolio of high efficiency, non-utility electricity generating facilities in northeast North America. On November 26, 2018, Emera announced an agreement to sell its three New England Gas Generating facilities. The transaction is expected to close in the first quarter of 2019. Refer to the “Developments” section for further details.

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 | Connecticut | 560 | 1999 | Natural gas | Selling electricity and capacity to ISO-NE |
| Tiverton | Rhode Island | 290 | 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** | | **1,115** | | | |
| **Maritime Canada** | | | | | |
| Bayside | New Brunswick | 290 | 2001 | Natural gas | Long-term PPA November - March; Selling electricity to Maritimes and ISO-NE for remainder of year; Selling capacity to ISO-NE |
| Brooklyn | Nova Scotia | 30 | 1996 | Biomass | Long-term PPA |
| **Total Maritime Canada** | | **320** | | | |
| **Total EEG** | | **1,435** | | | |

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 NEGG 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 due largely to power demand and fuel prices which impact margins. Winter and summer are generally the strongest periods, reflecting colder weather and fewer daylight hours in the winter season, and cooling load in the summer; and the impact on margins of generally higher natural gas pricing in the winter months when it is also required for heating load.

## Q4 Electricity and Capacity Sales

| For the<br>millions of Canadian dollars | | | | | | Three months ended<br>December 31 |
|---|---|---|---|---|---|---|
| | New England | | Maritime Canada | | Total | |
| | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 |
| Electricity sales | **$ 81** | $ 78 | **$ 11** | $ 9 | **$ 92** | $ 87 |
| Capacity sales | **40** | 27 | **-** | 1 | **40** | 28 |
| Electricity and capacity sales | **$ 121** | $ 105 | **$ 11** | $ 10 | **$ 132** | $ 115 |

## Q4 Non-Regulated Fuel for Generation and Purchased Power

| For the<br>millions of Canadian dollars | | | | | | Three months ended<br>December 31 |
|---|---|---|---|---|---|---|
| | New England | | Maritime Canada | | Total | |
| | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 |
| Non-regulated fuel for generation and purchased power | **$ 66** | $ 63 | **$ 2** | $ 1 | **$ 68** | $ 64 |

## Annual Electricity and Capacity Sales

| For the<br>millions of Canadian dollars | | | | | | Year ended<br>December 31 |
|---|---|---|---|---|---|---|
| | New England | | Maritime Canada | | Total | |
| | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 |
| Electricity sales | **$ 279** | $ 209 | **$ 30** | $ 53 | **$ 309** | $ 262 |
| Capacity sales | **136** | 80 | **-** | 3 | **136** | 83 |
| Electricity and capacity sales | **$ 415** | $ 289 | **$ 30** | $ 56 | **$ 445** | $ 345 |

## Annual Non-Regulated Fuel for Generation and Purchased Power

| For the<br>millions of Canadian dollars | | | | | | Year ended<br>December 31 |
|---|---|---|---|---|---|---|
| | New England | | Maritime Canada | | Total | |
| | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 |
| Non-regulated fuel for generation and purchased power | **$ 226** | $ 175 | **$ 11** | $ 35 | **$ 237** | $ 210 |

Emera Energy evaluates electricity sales and non-regulated fuel for generation and purchased power on a combined basis (excluding Capacity sales) for its NEGG facilities because the sales price of electricity and the cost of natural gas used to generate it are highly correlated in that market. NEGG's electricity sales net of non-regulated fuel for generation and purchased power was $15 million in Q4 2018 and Q4 2017.

NEGG's electricity sales net of non-regulated fuel for generation and purchased power was $53 million in 2018, compared to $34 million in 2017. This increase of $19 million was due to the impact of an unplanned outage at Bridgeport Energy from mid-March 2017 to mid-June 2017 and higher realized electricity pricing in 2018 compared to 2017, reflecting more favourable market conditions, specifically the impact of weather.

Capacity sales increased $12 million to $40 million in Q4 2018, compared to $28 million in Q4 2017; and increased $53 million to $136 million in 2018, compared to $83 million in 2017. These increases reflected higher capacity prices that came into effect for NEGG in June 2017 and June 2018.

The year-over-year reduction in electricity sales and non-regulated fuel for generation and purchased power in Maritime Canada in 2018, compared to 2017, reflected renegotiation of the Bayside Power PPA, providing increased dispatch flexibility, while maintaining the net revenue stream for the facility.

**Operating Statistics**

| For the | | | | | Three months ended | December 31 |
|---|---|---|---|---|---|---|
| | Sales Volumes (GWh) (1) | | Plant Availability (%) (2) | | Net Capacity Factor (%) (3) | |
| | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 |
| New England | **1,269** | 1,413 | **86.3%** | 94.9% | **51.5%** | 57.4% |
| Maritime Canada | **32** | 40 | **89.7%** | 77.8% | **4.5%** | 5.6% |
| Total | **1,301** | 1,453 | **87.0%** | 91.0% | **41.0%** | 45.8% |

| For the | | | | | Year ended December 31 | |
|---|---|---|---|---|---|---|
| | Sales Volumes (GWh) (1) | | Plant Availability (%) (2) | | Net Capacity Factor (%) (3) | |
| | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 |
| New England | **5,386** | 3,909 | **91.5%** | 81.8% | **55.1%** | 40.0% |
| Maritime Canada | **373** | 700 | **93.8%** | 73.0% | **13.3%** | 25.0% |
| Total | **5,759** | 4,609 | **92.0%** | 79.9% | **45.8%** | 36.7% |

(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 per cent 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.

NEGG sales volumes, plant availability and net capacity factor were lower quarter-over-quarter, reflecting more planned outage hours at the Bridgeport facility in Q4 2018. Year-over-year sales volumes, plant availability and net capacity factor were higher due to the impact of an unplanned outage at the Bridgeport facility from mid-March to mid-June 2017 and favourable market conditions in Q3 2018, compared to Q3 2017.

Maritime Canada plant availability was higher year-over-year due to a planned outage at the Bayside facility in Q2 2017. Sales volumes and capacity factor were lower due to negotiated changes to Bayside Power's PPA.

# Corporate and Other

| For the<br>millions of Canadian dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| Operating revenues – regulated gas | **$ 16** | $ 13 | **$ 57** | $ 52 |
| Non-regulated operating revenue | **12** | 19 | **47** | 75 |
| Total operating revenue | **$ 28** | $ 32 | **$ 104** | $ 127 |
| Intercompany revenue (1) | **10** | 10 | **39** | 39 |
| Income from equity earnings | **21** | 26 | **109** | 96 |
| Interest expense, net (2) | **78** | 76 | **304** | 293 |
| Adjusted contribution to consolidated net income | **$ (31)** | $ (1) | **$ (97)** | $ (88) |
| After-tax mark-to-market gain (loss) | **(1)** | - | **(2)** | 2 |
| Revaluation of US non-regulated deferred income taxes | **-** | (46) | **-** | (46) |
| Contribution to consolidated net income (loss) | **$ (32)** | $ (47) | **$ (99)** | $ (132) |
| Adjusted contribution to consolidated earnings per common share – basic | **$ (0.13)** | $ - | **$ (0.42)** | $ (0.41) |
| Contribution to consolidated earnings per common share – basic | **$ (0.14)** | $ (0.22) | **$ (0.42)** | $ (0.62) |
| Adjusted EBITDA | **$ 13** | $ 45 | **$ 131** | $ 136 |

(1) Intercompany revenue consists of interest from Brunswick Pipeline, M&NP and EEG.
(2) Interest expense, net excludes a pre-tax mark-to-market loss of $1 million in Q4 2018 (2017 - nil) and a loss of $2 million for the year-end December 31, 2018 (2017 - $ 3 million gain).

## 2017 Revaluation of US Non-regulated Deferred Income Taxes

In Q4 2017, due to enactment of the *US Tax Cuts and Jobs Act of 2017*, Corporate recorded a $46 million non-cash income tax expense resulting from the provisional revaluation of existing US non-regulated net deferred income tax assets. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. Management believes excluding this revaluation from adjusted net income better distinguishes the ongoing operations of the business, and allows investors to better understand and evaluate the Company.

## Net Income

Highlights of the net 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 (loss) – 2017** | **$** | **(47)** | **$** | **(132)** |
| Decreased non-regulated operating revenue due to less project activity at EUS | | (7) | | (28) |
| Increased non-regulated direct costs quarter-over-quarter due to higher project costs in Q4 2018. Decreased non-regulated direct costs year-over-year due to lower project activity at EUS | | (6) | | 16 |
| Increased OM&G quarter-over-quarter due to timing of performance-based compensation | | (12) | | (1) |
| Income from equity investments - see income from Equity Investments below | | (5) | | 13 |
| Increased interest expense | | (2) | | (11) |
| Increased income tax recovery year-over-year due to remeasurement of certain deferred tax balances as a result of a change in Florida state tax apportionment factors and increased losses before provision for income taxes, partially offset by the reduction of the US federal corporate income tax rate | | 3 | | 13 |
| Revaluation of US non-regulated deferred income taxes in 2017 due to tax reform | | 46 | | 46 |
| Increased preferred stock dividends due to the issuance of preferred shares in Q2 2018 | | - | | (7) |
| Other | | (2) | | (8) |
| **Contribution to consolidated net income (loss) – 2018** | **$** | **(32)** | **$** | **(99)** |

Excluding the change in mark-to-market and the deferred tax revaluation in 2017, Corporate and Other's costs increased for the quarter and year-over-year. The increase in Q4 2018 was due to timing of performance-based compensation and changes in project costs. The year-over-year increase was due to lower project activity at EUS, increased interest expense and increased preferred dividends, partially offset by increased income tax recovery and increased equity earnings from NSPML and LIL.

## 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 | | |
|---|---|---|---|---|---|---|---|
| | | **2018** | | 2017 | | **2018** | 2017 |
| M&NP | **$** | **5** | $ | 6 | **$** | **22** | $ 23 |
| NSPML | | **5** | | 10 | | **45** | 36 |
| LIL | | **11** | | 10 | | **42** | 37 |
| Income from equity investments | **$** | **21** | $ | 26 | **$** | **109** | $ 96 |

In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI. Prior to Q1 2018, NSPML recorded non-cash AFUDC earnings as it was under construction.

# LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash from its various regulated and non-regulated energy investments and select asset sales. Utility customer bases are diversified by both sales volumes and rates 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 sufficient cash include general economic downturns in markets served by Emera, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets and changes in environmental legislation. Cash flows generated from the sale of select assets are dependent on the market for the assets, acceptable pricing and the timing of the close of any sales. Emera's subsidiaries 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 and maintain their credit metrics.

Emera's future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera expects to invest approximately $6.5 billion over the three-year period from 2019 to 2021 on rate base growth in the Company's regulated utilities. Over 85 per cent of the investment is expected to be in Florida and Nova Scotia. Capital expenditures at the regulated utilities are subject to regulatory approval. Emera plans to use cash from operations, debt raised at the utilities and proceeds from the NEGG and other select asset sales to support normal operations, repayment of existing debt and capital requirements. Emera has credit facilities with varying maturities that cumulatively provide $3.1 billion of credit (refer to notes 22 and 24 in the consolidated financial statements for additional information regarding the credit facilities).

As a result of US tax reform, 2019 base rates have been adjusted in the majority of Emera's US regulated utilities to reflect lower income tax expense and amortization of the deferred income tax regulatory liability recorded at the date of enactment. The resulting decrease in cash from operations will be partially offset by cash refunds associated with Alternative Minimum Tax ("AMT") credits beginning in 2019.

Emera believes its liquidity is adequate given the Company's expected operating cash flows, capital expenditures, and related financing plans.

## Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the years ended December 31, 2018 and 2017 include:

| millions of Canadian dollars | **2018** | 2017 | $ Change |
|---|---|---|---|
| Cash, cash equivalents and restricted cash, beginning of period | **$ 503** | $ 491 | $ 12 |
| **Provided by (used in):** | | | |
| Operating cash flow before changes in working capital | **1,806** | 1,297 | 509 |
| Change in working capital | **(116)** | (104) | (12) |
| Operating activities | **1,690** | 1,193 | 497 |
| Investing activities | **(2,190)** | (1,761) | (429) |
| Financing activities | **344** | 593 | (249) |
| Effect of exchange rate changes on cash and cash equivalents | **25** | (13) | 38 |
| Cash, cash equivalents and restricted cash, end of period | **$ 372** | $ 503 | $ (131) |

**Cash Flow from Operating Activities**

Net cash provided by operating activities for the year ended December 31, 2018 increased $497 million to $1,690 million, compared to $1,193 million in 2017.

Cash from operations before changes in working capital increased $509 million. This was due to lower under-recovery from customers on clause related costs in 2018 than 2017, and lower pension contributions in 2018 at Emera Florida and New Mexico, increased capacity payments at NEGG, and increased marketing and trading margin at EES. These were partially offset by increased fuel for generation and purchased power at NSPI.

Changes in working capital decreased operating cash flows by $12 million. This decrease was due to unfavourable changes in cash collateral at NSPI and unfavourable changes in inventory at NSPI reflecting increased fuel purchases. These were partially offset by favourable changes in accounts receivable and accounts payable at Emera Florida and New Mexico, and NSPI and favourable changes in cash collateral at Emera Energy.

**Cash Flow Used in Investing Activities**

Net cash used in investing activities increased $429 million to $2,190 million for the year ended December 31, 2018, compared to $1,761 million in 2017 due to an increase in capital expenditures, partially offset by reduced equity contributions in NSPML and LIL in 2018, compared to 2017.
.
Capital expenditures, including AFUDC and net of proceeds from disposal of assets, for the year ended December 31, 2018 were $2,178 million, compared to $1,537 million in 2017. Details of capital expenditures are shown below:

- $1,567 million at Emera Florida and New Mexico (2017 - $914 million)
- $350 million at NSPI (2017 - $393 million)
- $103 million at Emera Maine (2017 - $85 million)
- $87 million at Emera Caribbean (2017 - $72 million)
- $33 million at Emera Energy (2017 - $47 million)
- $38 million at Corporate and Other (2017 – $26 million)

**Cash Flow from Financing Activities**

Net cash provided by financing activities decreased $249 million to $344 million for the year ended December 31, 2018, compared to $593 million in 2017. The decrease was due to the issuance of common stock in 2017 and increased 2018 dividends on common stock. These were partially offset by the issuance of preferred stock in 2018, increased borrowings under Emera's committed credit facilities in 2018, and a net increase of debt at Emera Florida and New Mexico.

# Working Capital

As at December 31, 2018, Emera's cash and cash equivalents were $316 million (2017 – $438 million) and Emera's investment in non-cash working capital was $449 million (2017 – $322 million). Of the cash and cash equivalents held at December 31, 2018, $280 million was held by Emera's foreign subsidiaries (2017 – $174 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.

## Contractual Obligations

As at December 31, 2018, commitments for each of the next five years and in aggregate thereafter consisted of the following:

| millions of Canadian dollars | | 2019 | 2020 | 2021 | 2022 | 2023 | Thereafter | Total |
|---|---|---|---|---|---|---|---|---|
| Long-term debt principal | $ | 1,119 $ | 898 $ | 1,742 $ | 758 $ | 1,138 $ | 9,847 $ | 15,502 |
| Interest payment obligations (1) | | 708 | 660 | 603 | 554 | 529 | 6,885 | 9,939 |
| Purchased power (2) | | 204 | 203 | 209 | 208 | 209 | 2,194 | 3,227 |
| Transportation (3) (4) | | 569 | 347 | 255 | 215 | 170 | 1,492 | 3,048 |
| Pension and post-retirement obligations (5) | | 38 | 34 | 35 | 36 | 36 | 1,040 | 1,219 |
| Fuel and gas supply | | 642 | 237 | 49 | 7 | 3 | - | 938 |
| Capital projects (6) | | 524 | 147 | 45 | 11 | 3 | 8 | 738 |
| Long-term service agreements (7) (8) | | 110 | 67 | 42 | 30 | 33 | 246 | 528 |
| Asset retirement obligations | | 3 | 27 | 45 | 1 | 1 | 365 | 442 |
| Equity investment commitments (9) | | - | 190 | - | - | - | - | 190 |
| Leases and other (10) | | 18 | 15 | 10 | 9 | 7 | 75 | 134 |
| Demand side management | | 44 | 1 | - | - | - | - | 45 |
| Long-term payable | | 4 | 5 | 5 | 5 | 5 | - | 24 |
| Convertible debentures | | - | - | - | - | - | 3 | 3 |
| | $ | 3,983 $ | 2,831 $ | 3,040 $ | 1,834 $ | 2,134 $ | 22,155 $ | 35,977 |

(1) 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, 2018, including any expected required payment under associated swap agreements.

(2) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.

(3) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.

(4) Includes $82 million related to NEGG transportation capacity ($5 million in 2019; $5 million in 2020; $5 million in 2021; $4 million in 2022; $4 million in 2023 and $59 million thereafter). On completion of the sale of the NEGG facilities, the remaining future contractual obligations will be transferred to the buyer. Refer to "Developments" for additional information.

(5) Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2018. Credited service and earnings are assumed to be crystallized as at December 31, 2018. The Company's contractual obligations for post-retirement (non-pension) benefits assume members must be age 55 or over (50 for TECO Energy) as at December 31, 2018 to be eligible. As the defined benefit pension plans currently undergo 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.

(6) Includes $439 million of commitments related to Tampa Electric's solar and Big Bend Power Station modernization projects.

(7) 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) Includes $248 million related to various long-term service agreements NEGG has entered into for maintenance of certain generating equipment ($46 million in 2019; $9 million in 2020; $24 million in 2021; $16 million in 2022; $16 million in 2023 and $137 million thereafter). On completion of the sale of the NEGG facilities, the remaining future contractual obligations will be transferred to the buyer. Refer to "Developments" for additional information.

(9) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.

(10) Operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years. In January 2018, NSPI started paying the UARB approved interim assessment payments and, as of December 31, 2018, $96 million had been paid to NSPML. The UARB approved payment for 2019 is $111 million and is subject to a $10 million holdback. Refer to note 14 to the consolidated financial statements for the year ended December 31, 2018 for additional information. After 2019, the timing of and amounts payable to NSPML will be subject to regulatory filings with the UARB, with expected filings in 2019 and 2020.

## Forecasted Gross Consolidated Capital Expenditures

2019 forecasted gross consolidated capital expenditures are as follows:

| millions of Canadian dollars | Emera Florida and New Mexico | NSPI | Emera Maine | Emera Caribbean | Emera Energy | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| Generation | $ 509 | $ 105 | $ - | $ 96 | $ 8 | $ - | $ 718 |
| New renewable generation | 282 | - | - | 16 | - | - | 298 |
| Transmission | 68 | 60 | 33 | 2 | - | - | 163 |
| Distribution | 323 | 125 | 32 | 33 | - | - | 513 |
| Gas transmission and distribution | 479 | - | - | - | - | - | 479 |
| Facilities, equipment, vehicles, and other | 161 | 50 | 31 | 12 | - | 6 | 260 |
| | $ 1,822 | $ 340 | $ 96 | $ 159 | $ 8 | $ 6 | $ 2,431 |

## Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate; access to approximately $3.1 billion committed syndicated revolving bank lines of credit in either CAD or USD per the table below.

| millions of dollars | **Maturity** | **Revolving Credit Facilities** | **Utilized** | **Undrawn and Available** |
|---|---|---|---|---|
| Emera – Operating and acquisition credit facility | June 2020 – Revolver | $ 900 | $ 411 | $ 489 |
| Emera Florida and New Mexico - in USD - credit facilities | March 2019 - March 2022 | 1,500 | 871 | 629 |
| NSPI – Operating credit facility | October 2023 – Revolver | 600 | 518 | 82 |
| Emera Maine – in USD – Operating credit facility | February 2023 – Revolver | 80 | 24 | 56 |
| Other – in USD – Operating credit facilities | Various | 32 | 11 | 21 |

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 as at December 31, 2018. Emera's significant covenant is listed below:

| | **Financial Covenant** | **Requirement** | As at **December 31, 2018** |
|---|---|---|---|
| **Emera** | | | |
| Syndicated credit facilities | Debt to capital ratio | Less than or equal to 0.70 to 1 | 0.60 : 1 |

Recent financing activities for Emera and its subsidiaries are discussed below:

**Emera**

On May 31, 2018, Emera issued 12 million 4.90 per cent Cumulative Minimum Rate Reset First Preferred Shares, Series H at $25.00 per share for gross proceeds of $300 million and net proceeds of $295 million. The net proceeds of the preferred share offering were used for general corporate purposes. For further details, refer to note 27 to the 2018 annual consolidated financial statements. The offering was made under Emera's $750 million short form base shelf prospectus dated May 16, 2018. As at December 31, 2018, the Company has $450 million available for issuance under this prospectus, which expires on June 16, 2020.

**Emera Florida and New Mexico**

On October 4, 2018, TEC completed a $375 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.45 per cent and have a maturity date of June 15, 2049. On October 11, 2018 proceeds from this issuance were used to repay a $300 million USD 1-year term credit facility.

On June 7, 2018, TEC completed a $350 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.30 per cent and have a maturity date of June 15, 2048.

On April 10, 2018, TECO Energy/Finance repaid a $250 million USD note upon maturity. The note was repaid using funds from existing credit facilities and cash on hand.

On March 23, 2018, TEC extended the maturity date of its $150 million USD accounts receivable collateralized borrowing facility from March 23, 2018 to March 22, 2021. There were no other changes in commercial terms.

On March 7, 2018, TECO Energy/Finance increased its $300 million USD revolving credit facility by $100 million USD to $400 million USD. There were no other changes in commercial terms.

On March 7, 2018, TECO Energy/Finance increased its $400 million USD term bank credit facility by $100 million USD to $500 million USD, and extended the maturity date from March 8, 2018 to March 8, 2019. There were no other changes in commercial terms.

**NSPI**

On October 31, 2018, NSPI amended its operating credit facility to extend the maturity from October 2021 to October 2023. There were no other changes in commercial terms.

**Emera Maine**

On November 15, 2018, Emera Maine completed a $50 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.71 per cent and will mature on November 15, 2048. Proceeds from this issuance were used for general corporate purposes.

On February 28, 2018, Emera Maine extended the maturity date of its $80 million USD operating credit facility from September 25, 2019 to February 28, 2023. There were no other changes in commercial terms.

**ECI**

On January 12, 2018, a wholly owned indirect subsidiary of ECI entered into a five year $18 million Bahamian dollar loan agreement with an interest rate of 4.00 per cent and maturity date of January 12, 2023.

**EBP**

On October 31, 2018, Emera Brunswick Pipeline amended its Credit Agreement to extend the maturity from February 2021 to February 2022. There were no other changes in commercial terms.

## Credit Ratings

Emera and its subsidiaries have been assigned the following senior unsecured debt ratings:

| | S&P | Moody's | DBRS |
|---|---|---|---|
| Emera Inc. | BBB (Negative) | Baa3 (Negative) | N/A |
| TECO Energy/TECO Finance | BBB (Negative) | Baa2 (Stable) | N/A |
| TEC | BBB+ (Negative) | A3 (Stable) | N/A |
| NMGC | BBB+ (Negative) | N/A | N/A |
| NSPI | BBB+ (Negative) | N/A | A (low) (Stable) |

On December 21, 2018, DBRS Limited affirmed NSPI’s A (low) issuer and issue rating with a stable trend.

On December 19, 2018, Moody’s Investor Services affirmed Emera’s Baa3 (Negative) issuer rating and Emera US Finance LP’s Baa3 guaranteed senior unsecured rating. At the same time, Moody’s affirmed the Baa2 senior unsecured ratings of TECO Energy/TECO Finance and the A3 issuer and senior unsecured ratings of Tampa Electric Company, with a stable outlook.

On December 5, 2018, S&P Global Ratings affirmed its BBB+ long term corporate credit rating on Emera, NSPI, TECO Energy/Finance, TEC and NMGC and changed its ratings outlook to negative from stable.

## Share Capital

As at December 31, 2018, Emera had 234.12 million (2017 – 228.77 million) common shares issued and outstanding. For the year ended December 31, 2018, 5.34 million common shares were issued (2017 – 18.6 million) for net proceeds of $215 million (2017 – $857 million).

As at December 31, 2018, Emera had 41 million preferred shares issued and outstanding (2017 – 29 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 five-year period for the plans. The cash required in 2019 for defined benefit pension plans is expected to be $53 million (2018 – $51 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 $33 million for 2019 (2018 – $31 million actual).

**Defined Benefit Pension Plan Summary**

| in millions of Canadian dollars | | | | | As at December 31, 2018 |
|---|---|---|---|---|---|
| **Plans by region** | **TECO Energy Pension Plans** | **NSPI Pension Plans** | **Emera Maine Pension Plans** | **Caribbean Plans** | **Total** |
| Assets as at December 31, 2018 | $ 899 | $ 1,220 | $ 170 | $ 11 | $ 2,300 |
| Accounting obligation at December 31, 2018 | 1,023 | 1,406 | 206 | 15 | 2,650 |
| Accounting expense during fiscal 2018 | $ 25 | $ 40 | $ 4 | $ 1 | $ 70 |

# OFF-BALANCE SHEET ARRANGEMENTS

## Defeasance

Upon privatization 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, 2018 totalled $759 million (2017 – $726 million). The securities are held in trust for an affiliate of the Province of Nova Scotia. Approximately 80 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.

## Guarantees and Letters of Credit

Emera has the following significant guarantees and letters of credit on behalf of third parties outstanding that are not included within the Consolidated Balance Sheets as at December 31, 2018:

TECO Energy has issued a guarantee in connection with SeaCoast's performance of obligations under a gas transportation precedent agreement. The guarantee is for a maximum potential amount of $45 million USD if SeaCoast fails to pay or perform under the contract. The guarantee expires five years after the gas transportation precedent agreement termination date, which is expected to terminate on January 1, 2022. In the event that TECO Energy's and Emera's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of $27 million USD.

The Company has standby letters of credit and surety bonds in the amount of $67 million USD to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one year term and are renewed annually as required.

Emera Reinsurance Limited has issued a standby letter of credit to secure its obligations under reinsurance agreements. The letter of credit expires in February 2019 and is renewed annually. The amount committed as of December 31, 2018 was $6 million USD.

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The letter of credit expires in June 2019 and is renewed annually. The amount committed as at December 31, 2018 was $49 million.

# DIVIDEND PAYOUT RATIO

Emera has provided annual dividend growth guidance of four to five per cent through 2021. The Company targets a long-term dividend payout ratio of 70 to 75 per cent, and while the payout ratio is likely to exceed that target in the forecast period, it is expected to return to that range over time. Emera Incorporated's common share dividends paid in 2018 were $2.2825 ($0.5650 in Q1, Q2, and Q3 and $0.5875 in Q4) per common share and $2.1325 ($0.5225 in Q1, Q2, and Q3 and $0.5650 in Q4) per common share for 2017, representing a payout ratio of 79 per cent of adjusted net income in 2018 and 86 per cent for 2017.

On August 9, 2018, Emera's Board of Directors approved an increase in the annual common share dividend rate from $2.26 to $2.35. The first quarterly dividend payment at the increased rate was paid on November 15, 2018.

# 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. Intercompany balances and intercompany 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. All material amounts are under normal interest and credit terms.

Significant transactions between Emera and its associated companies are as follows:

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $21 million (2017 – nil) for the three months ended December 31, 2018 and $97 million for the year ended December 31, 2018 (2017 – nil). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments. Refer to the "Business Overview and Outlook - Corporate and Other - ENL" and "Contractual Obligations" sections for further details.

- Natural gas transportation capacity purchases from M&NP are reported in the Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $7 million (2017 – $8 million) for the three months ended December 31, 2018 and $29 million for the year ended December 31, 2018 (2017 – $28 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Consolidated Balance Sheets as at December 31, 2018 and at December 31, 2017.

# 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 and consistency of income, and cash flow. In this section, Emera describes these principal risks that management believes could materially affect its business, revenues, operating income, net income, net assets, 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. As cost-of-service utilities with an obligation to serve customers, Tampa Electric, PGS, NMGC, NSPI, Emera Maine, BLPC, GBPC, and Domlec must obtain regulatory approval to change rates and/or riders from their respective regulators. Costs and investments can be recovered upon approval by the respective regulator as an adjustment 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 changes in government and significant shifts in government policy including initiatives regarding deregulation or restructuring of the energy industry and shifts in policy which could occur as a result of climate change concerns. Emera's investments in entities in which it has significant influence and which are subject to regulatory risk include NSPML, LIL, M&NP and Lucelec.

Deregulation or restructuring of the electric industry may result in increased competition and unrecovered costs that could adversely affect operations, net income and cash flows. Florida electric utilities, including Tampa Electric, have limited competition in their market for retail customers; however, there is currently a proposed constitutional initiative in Florida which, if passed, would grant customers of investor-owned utilities the right to choose their electricity provider and to generate and sell electricity, and would limit the business of investor-owned utilities to construction, operation and repair of electrical transmission and distribution systems. This initiative is going through the process for potential inclusion as an amendment to the Florida Constitution, to be voted on in November 2020. Such a vote would be subject to Florida Supreme Court approving the placing of the amendment on the ballot and conditional on the initiative attracting a sufficient number of petition signatures. In the event the amendment achieves the 60 per cent required votes, the implementing legislation would be required to be passed by no later than June 1, 2023 and with effect by no later than 2025.

During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these rate regulated companies, and their respective regulators determine whether to allow recovery and to adjust rates based upon the 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 has a 25-year firm service agreement, expiring in 2034, with Repsol Energy Canada (“REC”). This firm service agreement was filed with the NEB, and 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. In the absence of a complaint, the NEB does not normally undertake a detailed examination of Brunswick Pipeline’s tolls.

**Weather and Climate Change Risk**

The Company is subject to a number of risks that arise or may arise from weather and climate change, including seasonal variations, the risk of changes in regulations (refer to “Changes in Environmental Legislation” risk), more frequent and intense weather events, and warming air temperatures.

Fluctuations in the amount of electricity or natural gas used by customers can vary significantly in response to seasonal changes in weather and could impact the operations, results of operations, financial condition and cash flows of the Company’s utilities. For example, electrical utilities operating in the US Northeast or Atlantic Canada could see lower demand in winter months if temperatures are warmer than expected. In the absence of a regulatory recovery mechanism for unanticipated resulting revenue losses, such events could have an effect on the results of operations, financial conditions or cash flows of the Company or its utilities.

Climate change is predicted to lead to increased frequency and intensity of weather events and related impacts such as storms, wildfires, flooding and storm surge. Extreme weather events create a risk of physical damage to the Company’s assets. High winds can damage structures, and cause widespread damage to transmission and distribution infrastructure. Increased frequency and severity of weather events increases the likelihood that the duration of power outages and fuel supply disruptions could increase. Increased intensity of flooding could adversely affect the operations of the Company’s hydro-electric facilities.

The potential impacts of climate change, such as rising sea levels and larger storm surges from more intense hurricanes, can combine to produce greater damage to coastal located generation and other facilities. Each of Emera’s regulated electric utilities have programs for storm hardening of transmission and distribution facilities to minimize damage, but there can be no assurance that these measures will fully mitigate the risk. This risk to transmission and distribution facilities is generally not insured, and as such the restoration cost is generally recovered through regulatory processes, either in advance through reserves or designated self-insurance funds, or after the fact through the establishment of regulatory assets. Recovery is not assured and is subject to prudency review. The risk to generation assets is, in part, mitigated through the design, siting, construction and maintenance of such facilities, regular risk assessments, engineered mitigation, emergency storm response plans and insurance risk transfer.

Climate change is also characterized by increases in global air temperatures. Increased air temperatures may bring increased frequency and severity of wildfires, including within the Company’s service territories in the southern United States. Increased air temperatures could also result in decreased efficiencies over time of both generation and transmission facilities.

The increased risk of wildfires is addressed primarily through asset management programs for natural gas transmission and distribution operations, and vegetation management programs for electric transmission and distribution facilities. If it is found to be responsible for such a fire, the Company could suffer costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes and could materially affect Emera’s business and financial results including its reputation with customers, regulators, governments and financial markets. Resulting costs could include fire suppression costs, regeneration, timber value, increased insurance costs and costs arising from damages and losses incurred by third parties.

**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 GHG emissions standards and air emissions standards. Emera is also subject to laws regarding waste management, wastewater discharges and aquatic and terrestrial habitats.

Beginning January 1, 2019, each province and territory in Canada is required to have a carbon pricing system which meets a benchmark set by the Government of Canada, failing which the Government of Canada would impose a carbon pricing system on each non-compliant province or territory equivalent to the federal benchmark. On October 23, 2018, the Government of Canada confirmed that the cap and trade carbon pricing system proposed by the Government of Nova Scotia met the federal benchmark. In the United States, the Environmental Protection Agency released a proposed rule to replace the Clean Power Plan, named the Affordable Clean Energy ("ACE") rule. The ACE rule proposes to establish GHG emission guidelines for states to address GHG emissions from existing fossil fuel-fired electricity generating units. Individual states continue to develop or administer GHG reduction initiatives. 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.

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. In addition, Emera's business could be materially affected by changes in government policy, utility regulation, and environmental and other legislation that could occur in response to environmental and climate change concerns.

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and with the objective of complying with applicable legal requirements and Company policy. 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.

**Cybersecurity Risk**

Emera is exposed to potential risks related to cyberattacks and unauthorized access. The Company increasingly relies on information technology systems and network infrastructure to manage its business and safely operate its assets; including controls for interconnected systems of generation, distribution and transmission as well as financial, billing and other business systems. Emera also relies on third party service providers in order to conduct business. As the Company operates critical infrastructure, it may be at greater risk of cyberattacks by third parties, which could include nation-state controlled parties.

Cyberattacks can reach the Company's networks with access to critical assets and information via their interfaces with less critical internal networks or via the public internet. Cyberattacks can also occur via personnel with direct access to critical assets or trusted networks. Methods used to attack critical assets could include general purpose or energy-sector-specific malware delivered via network transfer, removable media, viruses, attachments or links in e-mails. The methods used by attackers are continuously evolving and can be difficult to predict and detect.

Despite security measures in place, the Company's systems, assets and information could experience security breaches that could cause system failures, disrupt operations or adversely affect safety. Such breaches could compromise customer, employee-related or other information systems and could result in loss of service to customers or the unavailability, release, destruction or misuse of critical, sensitive or confidential information. These breaches could also delay delivery or result in contamination or degradation of hydrocarbon products the Company transports, stores or distributes.

Should such cyberattacks or unauthorized accesses materialize, the Company could suffer costs, losses and damages all, or some of which, may not be recoverable through insurance, legal, regulatory cost recovery or other processes and could materially adversely affect Emera's business and financial results including its reputation and standing with customers, regulators, governments and financial markets. Resulting costs could include, amongst others, response, recovery and remediation costs, increased protection or insurance costs and costs arising from damages and losses incurred by third parties. If any such security breaches occur, there is no assurance that they can be adequately addressed in a timely manner.

The Company seeks to manage these risks by aligning to a common set of cybersecurity standards, program maturity objectives and strategy derived, in part, on the National Institute of Standards and Technology's Cyber Security Framework. With respect to certain of its assets, the Company is required to comply with rules and standards relating to cybersecurity and information technology including, but not limited to, those mandated by bodies such as the North American Electric Reliability Corporation and Northeast Power Coordinating Council. The status of key elements of the Company's cybersecurity program is reported to the Audit Committee on a quarterly basis.

**Energy Consumption Risk**

Emera's rate-regulated utilities are affected by demand for energy based on changing customer patterns due to fluctuations in a number of factors including general economic conditions, customers' focus on energy efficiency and advancements in new technologies, such as rooftop solar, electric vehicles and battery storage. Government policies promoting distributed generation, and new technology developments that enable those policies, have the potential to impact how electricity enters the system and how it is bought and sold. In addition, increases in distributed generation may impact demand resulting in lower load and revenues. These changes could negatively impact Emera's operations, rate base, net earnings and cash flows. The Company's rate-regulated utilities are focused on understanding customer demand, energy efficiency and government policy to ensure that the impact of these activities benefit customers, that they do not negatively impact the reliability of the energy service the utilities provide and that they are addressed through regulations.

**Foreign Exchange Risk**

The Company is exposed to foreign currency exchange rate changes. Emera operates internationally, with an increasing amount of the Company's adjusted net income earned outside of Canada. As such, Emera is exposed to movements in exchange rates between the Canadian dollar and, particularly, the US dollar, which could positively or adversely affect results.

Consistent with the Company's risk management policies, Emera manages currency risks through matching US denominated debt to finance its US operations and uses foreign currency derivative instruments to hedge specific transactions. The Company may enter into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams and capital expenditures. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including foreign exchange.

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries do not impact net income as they are reported in AOCI.

**Liquidity and Capital Market Risk**

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera manages this risk by forecasting 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, select asset sales, short-term credit facilities, and ongoing access to capital markets. Cash flows generated from the sale of select assets are dependent on the market for the assets, acceptable pricing and the timing of the close of any sales. The Company reasonably expects liquidity sources to exceed capital needs.

Emera's access to capital and cost of borrowing is subject to a number of risk factors, including financial market conditions and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in property, plant and equipment. Emera is subject to risk with changes in interest rates that could have an adverse effect on the cost of financing. Inability to access to cost-effective capital could have a material impact on Emera's ability to fund its growth plan.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the Company's business and regulatory framework, the ability to recover costs and earn returns, diversification, leverage, and liquidity. A decrease in 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. Emera manages this risk by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to reduce the earnings volatility derived from stock-based compensation, preferred share units and deferred share units.

**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.

For Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. Regulatory ROE will generally follow the direction of interest rates, such that regulatory ROE's are likely to fall in times of reducing interest rates and rise 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.

**Emera Energy Marketing and Trading**

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 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 commodities, primarily 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 the 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. The Company takes a strategic approach to hedging the volatility of pricing risk in these markets. When market prices are favourable, the Company will typically enter into hedging instruments that effectively fix the price of natural gas and electricity.

On November 26, 2018, Emera announced an agreement to sell its three NEGG facilities. The transaction is expected to close in the first quarter of 2019. Refer to the "Developments" section for further details.

**Counterparty 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 specific accounts.

**Country Risk**

Earnings outside of Canada constituted 69 per cent (65 per cent from the US and 4 per cent from the Caribbean) of Emera's earnings in 2018 (2017 – 42 per cent, with 35 per cent from the US and 7 per cent from the Caribbean). Emera's investments are currently in regions where political and economic risks are considered by the Company to be acceptable. Emera's operations in some countries may be subject to changes in 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. The Company mitigates this risk through a rigorous approval process for investment, and by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available in all affiliates.

**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 commercial relationship risk by monitoring credit risk, as discussed above in Counterparty 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**

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, with the exception of the TECO Energy Group Retirement Plan. The cost of providing these benefit plans varies depending on 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, contributions to the plans and the pension and post-retirement liabilities) 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.

Each of Emera's employee defined benefit pension plans are managed according to an approved investment policy and governance framework. Emera employs a long-term approach with respect to asset allocation and each investment policy outlines the level of risk which the Company is prepared to accept with respect to the investment of the pension funds in achieving both the Company's fiduciary and financial objectives. Studies are routinely undertaken every 3 to 5 years with the objective that the plans' asset allocations are appropriate for meeting Emera's long-term pension objectives.

**Labour Risk**

Emera's ability to deliver service to its customers and to execute its growth plan depends on attracting, developing and retaining a skilled workforce. Utilities are faced with demographic challenges related to trades, technical staff and engineers with an increasing number of employees expected to retire over the next several years. Failure to attract, develop and retain an appropriately qualified workforce could adversely affect the Company's operations and financial results. Emera seeks to manage this risk through maintaining competitive compensation programs, a dedicated talent acquisition team, human resources programs and practices including ethics and diversity training, employee engagement surveys, succession planning for key positions and apprenticeship programs.

Approximately 40 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have an adverse effect on the Company's earnings, cash flow and financial position. Emera seeks to manage this risk through ongoing discussions and working to maintain positive relationships 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.

Emera manages this risk through regular IT asset lifecycle management, dedicated project teams, executive oversight and appropriate governance structures and strong project management practices. Employees with extensive subject matter expertise assist in planning, project management, implementation and training. Formal back up and critical incident response practices ensure that continuity is maintained in the event of any disruptions or incidents.

## Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. The value of Emera's existing deferred tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws. Emera monitors the status of existing tax laws to ensure that changes impacting the Company are appropriately reflected in the Company's tax compliance filings and financial results.

## System Operating and Maintenance Risks

The safe and reliable operation of electric generation and electric and natural gas transmission and distribution systems is critical to Emera's operations. There are a variety of hazards and operational risks inherent in operating electric utilities and natural gas transmission and distribution pipelines. Electric generation, transmission and distribution operations can be impacted by risks such as mechanical failures, activities of third parties, damage to facilities and infrastructure caused by hurricanes, storms, falling trees, lightning strikes, floods, fires and other natural disasters. Natural gas pipeline operations can be impacted by risks such as leaks, explosions, mechanical failures, activities of third parties and damage to the pipelines facilities and equipment caused by hurricanes, storms, floods, fires and other natural disasters. Electric utility and natural gas transmission and distribution pipeline operation interruption could negatively affect revenue, earnings, and cash flows as well as customer and public confidence. Emera manages these risks by investing in a highly skilled workforce, operating prudently, preventative maintenance and making effective capital investments. Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all of these losses, which could adversely affect the Company's results of operations and cash flows.

## 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.

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.

The Company mitigates its uninsured risk by ensuring that insurance limits align with risk exposures, and for uninsured assets and operations, that appropriate risk assessments and mitigation measures are in place. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including uninsured losses.

# 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, interest rates and share prices through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of foreign exchange forwards and swaps, interest rate options and swaps, equity derivatives, 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 Tampa Electric, PGS, NMGC, 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 any gains or losses resulting from settlement of these derivatives will 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>2018** | | December 31<br>2017 |
|---|---|---|---|---|
| Derivative instrument assets (current and other assets) | **$** | **-** | $ | 7 |
| Derivative instrument liabilities (current and long-term liabilities) | | **(5)** | | (7) |
| Net derivative instrument assets (liabilities) | **$** | **(5)** | $ | - |

**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 |
|---|---|---|---|---|
| | | **2018** | | 2017 |
| Operating revenues – regulated | **$** | **5** | $ | (10) |
| Non-regulated fuel for generation and purchased power | | **1** | | 3 |
| Effective net gains (losses) | **$** | **6** | $ | (7) |

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

**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>2018** | | December 31<br>2017 |
|---|---|---|---|---|
| Derivative instrument assets (current and other assets) | **$** | **104** | $ | 181 |
| Regulatory assets (current and other assets) | | **6** | | 13 |
| Derivative instrument liabilities (current and long-term liabilities) | | **(6)** | | (13) |
| Regulatory liabilities (current and long-term liabilities) | | **(115)** | | (183) |
| Net asset (liability) | **$** | **(11)** | $ | (2) |

## 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 | Year ended December 31<br>**2018** | 2017 |
|---|---|---|
| Regulated fuel for generation and purchased power (1) | **$ 11** | $ 17 |
| Net gains (losses) | **$ 11** | $ 17 |

(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 or property plant and equipment will be recognized in "Regulated fuel for generation and purchased power" when the hedged item is consumed.

## HFT 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>2018** | December 31<br>2017 |
|---|---|---|
| Derivative instruments assets (current and other assets) | **$ 62** | $ 63 |
| Derivative instruments liabilities (current and long-term liabilities) | **(354)** | (290) |
| Net derivative instrument assets (liabilities) | **$ (292)** | $ (227) |

## 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 December 31<br>**2018** | 2017 |
|---|---|---|
| Non-regulated operating revenues | **$ 193** | $ 408 |
| Non-regulated fuel for generation and purchased power | **2** | 12 |
| Net gains (losses) | **$ 195** | $ 420 |

## 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>2018** | December 31<br>2017 |
|---|---|---|
| Derivative instrument assets (current and other assets) | **$ 1** | $ 2 |
| Net derivative instrument assets (liabilities) | **$ 1** | $ 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 December 31<br>**2018** | 2017 |
|---|---|---|
| Interest expense, net | **(1)** | 2 |
| Total gains (losses) | **$ (1)** | $ 2 |

# DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures (“DC&P”) and internal control over financial reporting (“ICFR”), as defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”). The Company’s internal control framework is based on the criteria published in the Internal Control - Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations (“COSO”) of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design and effectiveness of the Company’s DC&P and ICFR as at December 31, 2018 to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

Management recognizes the inherent limitations in internal control systems, no matter how well designed. Control systems determined to be appropriately designed can only provide reasonable assurance with respect to the reliability of financial reporting and may not prevent or detect all misstatements.

There were no changes in the Company’s ICFR during the quarter ended December 31, 2018, that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

# 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 and long-lived assets impairment assessments, income taxes, asset retirement obligations, capitalized overhead and valuation of financial instruments. Actual results may differ significantly from these estimates.

**Rate Regulation**

The rate-regulated accounting policies of Emera’s rate regulated subsidiaries and regulated equity investments are subject to examination and approval by their respective regulators and may differ from accounting policies for non-rate-regulated companies. 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 expectations of the future actions of the regulators. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered. The application of regulatory accounting guidance is a critical accounting policy as a change in these assumptions may result in a material impact on reported assets, liabilities and the results of operations.

The Company has recorded $1,569 million (2017 - $1,411 million) of regulatory assets and $2,610 million (2017 - $2,468 million) of regulatory liabilities as at December 31, 2018.

**Accumulated Reserve – Cost of Removal**

Tampa Electric, PGS, NMGC and NSPI recognize non-asset retirement obligation costs of removal as regulatory liabilities. These costs of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required costs of removal of property, plant and equipment upon retirement. The companies accrue for costs of removal over the life of the related assets based on depreciation studies approved by their respective regulators. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays. The balance of the Accumulated reserve – cost of removal within regulatory liabilities was $955 million at December 31, 2018 (2017 - $894 million).

**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 accounting related to employee post-retirement benefits is a critical accounting estimate. Changes in the estimated benefit obligation, affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings, could have a material impact on reported assets, liabilities, accumulated other comprehensive income and results of operations. 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 could change the annual pension funding requirements. This could have a significant impact on the Company's annual cash requirements.

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 changes to pension costs in future periods.

The Company's accounting policy is to amortize the net actuarial gain or loss, that 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 (for the largest plans this is currently 7.5 years for the Canadian plans and a weighted average of 12.4 years for the US plans). The Company's use of smoothed asset values 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 and is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year. The following table shows the discount rate for benefit cost purposes and the expected return on plan assets for each plan:

| | **2018** | | 2017 | |
|---|---|---|---|---|
| | **Discount rate for benefit cost purposes** | **Expected return on plan assets** | Discount rate for benefit cost purposes | Expected return on plan assets |
| TECO Energy Group Retirement Plan | **3.63 %** | **6.85 %** | 4.16 **%** | 7.00 **%** |
| TECO Energy Group Supplemental Executive Retirement Plan (1) | **3.11 / 3.84 %** | **N/A** | 3.37% / 3.25 **%** | N/A |
| TECO Energy Group Benefit Restoration Plan (1) | **3.26 / 3.76 / 4.01 %** | **N/A** | 3.64 **%** | N/A |
| TECO Energy Post-retirement Health and Welfare Plan | **3.70 %** | **N/A** | 4.28 **%** | N/A |
| New Mexico Gas Company Retiree Medical Plan | **3.71 %** | **4.00 %** | 4.29 **%** | 7.00 % |
| NSPI | **3.50 %** | **6.00 %** | 3.84 **%** | 6.00 % |
| Bangor Hydro (2) | **3.53 %** | **6.55 %** | 4.04 **%** | 6.55 % |
| Maine Public Service (2) | **3.45 %** | **6.55 %** | 3.91 **%** | 6.55 % |
| GBPC Salaried | **4.25 %** | **6.00 %** | 4.25 **%** | 6.00 % |
| GBPC Union | **5.00 %** | **5.00 %** | 5.00 **%** | 5.00 % |

(1) The discount rate for benefit cost purposes is updated throughout the year as special events occur, such as settlements and curtailments.
(2) Effective January 1, 2014, Bangor Hydro Electric Company and Maine Public Service Company merged to become Emera Maine.

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans was $115 million in 2018 (2017 - $105 million). The reported benefit cost is impacted by numerous assumptions, including the discount rate and asset return assumptions. A 0.25 per cent change in the discount rate and asset return assumptions would have had +/- impact on the 2018 benefit cost of $9 million and $6 respectively (2017 - $9 million and $6 million).

**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 Tampa Electric, PGS, NMGC, Emera Maine, BLPC, GBPC and Domlec. 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 determine 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, inter-period changes to customer classes and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2018, unbilled revenues totalled $296 million (2017 – $278 million) on total annual operating revenues of $6,524 million (2017 – $6,226 million).

**Property, Plant and Equipment**

Property, plant and equipment represents 58 per cent of total assets 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 and accumulated depreciation.

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. Depreciation expense was $881 million for the year ended December 31, 2018 (2017 – $833 million).

**Goodwill Impairment Assessments**

Goodwill is subject to an annual assessment for impairment at the reporting unit level. Reporting units are generally determined at the operating segment level or one level below the operating segment level. Reporting units with similar characteristics are grouped for the purpose of determining impairment, if any, of goodwill. Application of the goodwill impairment test requires management judgment. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. Significant assumptions used in the qualitative assessment include macroeconomic conditions, industry and market considerations and overall financial performance, among other factors.

If an entity performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, or if an entity chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Significant assumptions used in estimating the fair value of a reporting unit include discount and growth rates, rate case assumptions, valuation of net operating losses, utility sector market performance and transactions, projected operating and capital cash flows for the relevant business and the fair value of debt.

At December 31, 2018, the Company had goodwill with a total carrying amount of $6,313 million (December 31, 2017 – $5,805 million). The change in the carrying value from 2017 to 2018 was a result of the strengthening US dollar on the goodwill balances. This goodwill represents the excess of the acquisition purchase price for TECO Energy (Tampa Electric, PGS and NMGI reporting units), Emera Maine and GBPC over the fair values assigned to individual assets acquired and liabilities assumed.

The fair market value of goodwill is subject to change from period to period as assumptions about future cash flows are required. Adverse regulatory actions, such as significant reductions in the allowed ROE at Tampa Electric, PGS, NMGC, Emera Maine or GBPC could negatively impact goodwill in the future. In addition, changes in other fair value significant assumptions described above could also negatively impact goodwill in the future.

No impairment provisions with respect to goodwill were required for either 2018 or 2017.

**Long-Lived Assets Impairment Assessments**

In accordance with accounting guidance for long-lived assets, the Company assesses whether there has been an impairment of long-lived assets and intangibles when such indicators exist. The Company reviews all long-lived assets in the last quarter of each year to ensure that any gradual change over the year and the seasonality of the markets are considered when determining which assets require an impairment analysis. In the case of a triggering event, such as a significant market disruption or sale of a business, the values of related long-lived assets are reviewed outside of this annual analysis. The review of long-lived assets for impairment involves comparing the undiscounted expected future cash flows to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated fair value.

The Company believes accounting estimates related to asset impairments are critical estimates for the following reasons: 1) the estimates are highly susceptible to change, as management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and/or the current market conditions in such periods; 2) markets can experience significant uncertainties; 3) the estimates are based on the ongoing expectations of management regarding probable future uses and holding periods of assets; and 4) the impact of an impairment on reported assets and earnings could be material. The Company's assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The Company's expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

No material impairment provisions with respect to long-lived assets were required for 2018 or 2017.

**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 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.

The Company believes the accounting estimate related to income taxes is a critical estimate for the following reasons: 1) realization of deferred tax assets is dependent upon the generation of sufficient taxable income, both operating and capital, in future periods; 2) a change in the estimated valuation allowance could have a material impact on reported assets and results of operations; and 3) administrative actions of the tax authorities, changes in tax law or regulation, and the uncertainty associated with the application of tax statutes and regulations could change our estimate of income taxes, including the potential for elimination or reduction of our ability to realize tax benefits and to utilize deferred tax assets.

In response to the US enactment of the *Tax Cuts and Jobs Act* on December 22, 2017, Emera recorded an $813 million net revaluation of the Company's US deferred tax assets and liabilities at December 31, 2017. Management estimated the implications of the Act based on the best information available. No further adjustments were recorded in 2018 and the Company has completed its accounting for the revaluation of its US deferred income tax assets and liabilities resulting from the effects of the Act. The Company believes that its US based financing interest will be deductible under the Act. Any change in assumptions could have a material impact on the results of the Company. Refer to "Significant Items Affecting Earnings – US Tax Reform" for further details.

**Asset Retirement Obligations ("ARO")**

The measurement of the fair value of AROs requires the Company to make reasonable estimates concerning the method and timing of settlement associated with the legally obligated costs. There are uncertainties in estimating future asset-retirement costs due to potential events, such as changing legislation or regulations and advances in remediation technologies. Emera has AROs associated with the remediation of generation, transmission and distribution and pipeline assets.

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 recorded 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 generation, 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.

As at December 31, 2018, the AROs recorded on the balance sheet were $205 million (2017 – $172 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $451 million (2017 - $438 million), which will be incurred between 2019 and 2061. The majority of these costs will be incurred between 2028 and 2050.

**Capitalized Overhead**

As required by their respective regulators, Emera's rate regulated subsidiaries and regulated equity investments capitalize overhead costs that are attributable to the overall capital expenditure program. The methodology for the calculation of capitalized overhead is approved by the respective regulators. For the year ended December 31, 2018, $187 million of overhead costs (2017 – $156 million) 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**

The Company 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**

The Company 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. Only in limited circumstances does the Company enter into commodity transactions involving non-standard features where market observable data is not available, or contracts in which the terms extend beyond five years.

# CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2018, are described as follows:

**Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income**
In February 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Updates ("ASU") No. 2018-02, *Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. The standard allows reclassification from accumulated other comprehensive income to retained earnings for certain tax effects resulting from the *US Tax Cuts and Jobs Act* that would otherwise be stranded in accumulated other comprehensive income. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018, with early adoption permitted. The Company early adopted the standard in Q2 2018 and elected to not reclassify tax effects resulting from the *US Tax Cuts and Jobs Act* stranded in accumulated other comprehensive income to retained earnings as amounts were not material. Emera utilizes a portfolio approach to determine the timing and extent to which stranded income tax effects from items that were previously recorded in accumulated other comprehensive income are released.

**Revenue from Contracts with Customers**
On January 1, 2018, the Company adopted ASU 2014-09, *Revenue from Contracts with Customers* and all the related amendments, which created a new, principle-based revenue recognition framework. The standard has been codified as Accounting Standards Codification ("ASC") Topic 606. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled to. The guidance requires additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The Company adopted ASC 606 using the modified retrospective method. Results for reporting periods beginning after January 1, 2018 are presented under Topic 606, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting practices. The adoption of ASC 606 resulted in no adjustments to the Company's opening retained earnings as of the adoption date. The impact of the adoption of the new standard was immaterial to the Company's net income and is expected to be immaterial on an ongoing basis.

**Recognition and Measurement of Financial Assets and Financial Liabilities**
On January 1, 2018, the Company adopted ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities* and all of the related amendments. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The standard requires investments in equity securities, except those accounted for under the equity method of accounting or those that result in consolidation, to be measured at fair value. The Company has elected to measure equity securities that do not have a readily determinable fair value at cost minus impairment (if any), plus or minus observable price changes resulting from transactions for the identical or similar investments of the same issuer. The standard eliminates the available-for-sale classification for equity investments that recognized changes in the fair value as a component of other comprehensive income, resulting in all changes in fair value being recognized in net income. The impact as a result of the remeasurement of equity investments is expected to be immaterial to the Company's net income on an ongoing basis. A cumulative-effect adjustment of $4 million was made which increased retained earnings in the Consolidated Balance Sheet as of January 1, 2018.

**Clarifying the Definition of a Business**
In January 2017, the FASB issued ASU 2017-01, *Clarifying the Definition of a Business*. The standard provides guidance to assist entities with evaluating when a set of transferred assets and activities is a business. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and is required to be applied prospectively. The Company adopted ASU 2017-01 effective January 1, 2018. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

**Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost**
In March 2017, the FASB issued ASU 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost.* The guidance requires the service cost component of defined benefit pension or other postretirement benefit plans to be reported in the same line items as other compensation costs. The other components of net benefit cost are required to be presented in the Consolidated Statements of Income outside of income from operations. Only the service cost component is eligible for capitalization as property, plant and equipment under this guidance. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The guidance is required to be applied retrospectively for presentation in the Consolidated Statements of Income and prospectively for the guidance around capitalization.

The Company adopted ASU 2017-07 effective January 1, 2018 and December 31, 2017 balances have been retrospectively restated in the Consolidated Statements of Income. The standard allows the Company to use the amounts disclosed in its pension and other postretirement benefit plan note for the prior comparative periods as the estimation basis for applying the retrospective presentation requirements. This change resulted in $27 million of costs, previously presented within “Operating, maintenance and general”, being reclassified to “Other income (expense), net” in the Consolidated Statements of Income for the year ended December 31, 2017.

# FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by the FASB. The following updates have been issued by the FASB, but have not yet been adopted by Emera. Any ASUs not included below were assessed and determined to be either not applicable to the Company or have an insignificant impact on the consolidated financial statements.

**Leases**
In February 2016, the FASB issued ASU 2016-02, *Leases.* The standard, codified as ASC Topic 842, increases transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with terms of more than 12 months. Under the previous guidance, operating leases are not recorded as assets and liabilities on the balance sheet. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. The guidance will require additional disclosures regarding key information about leasing arrangements. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted and is required to be applied using a modified retrospective approach. The Company will not early adopt the standard.

In January 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The Company will make this election. In July 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The Company will make this election. Additionally, the Company will elect the options that allow the Company to not reassess whether any expired or existing contracts contain leases, carry forward existing lease classification, use hindsight to determine the lease term for existing leases and not separate lease components from non-lease components for all lessee and lessor arrangements.

Over the past several years, the Company developed and executed a project plan which included holding training sessions with key stakeholders throughout the organization, gathering detailed information on existing lease arrangements, evaluating implementation alternatives and calculating the lease asset and liability balances associated with individual contractual arrangements. The Company has implemented additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. Updates to systems are not required as a result of implementation of this standard. The adoption of this standard will affect the Company's financial position by increasing assets and liabilities related to operating leases by approximately $70 million, with no impact to the Company's Consolidated Statements of Income. There will be no significant changes to the Company's accounting for lessor arrangements as a result of the adoption of the standard. The Company is in the process of assessing the disclosure requirements and continues to monitor FASB amendments to ASC Topic 842.

**Measurement of Credit Losses on Financial Instruments**
In June 2016, the FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted for annual reporting periods, including interim periods after December 15, 2018 and will be applied using a modified retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

**Targeted Improvements to Accounting for Hedging Activities**
In August 2017, the FASB issued ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities,* which amends the hedge accounting recognition and presentation requirements in ASC Topic 815. This standard improves the transparency and understandability of information about an entity's risk management activities by better aligning the entity's financial reporting for hedging relationships with those risk management activities and simplifies the application of hedge accounting. The standard will make more financial and nonfinancial hedging strategies eligible for hedge accounting, amends the presentation and disclosure requirements for hedging activities and changes how entities assess hedge effectiveness. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018, with early adoption permitted, and is required to be applied using a modified retrospective approach. The adoption of this standard will have no impact on the Company's consolidated financial statements.

**Cloud Computing**

In August 2018, the FASB issued ASU 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract.* The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted and can be applied either retrospectively or prospectively. The Company is currently evaluating the transition methods and the impact of the adoption of this standard on the consolidated financial statements.

# SUMMARY OF QUARTERLY RESULTS

| For the quarter ended millions of Canadian dollars (except per share amounts) | **Q4 2018** | **Q3 2018** | **Q2 2018** | **Q1 2018** | Q4 2017 | Q3 2017 | Q2 2017 | Q1 2017 |
|---|---|---|---|---|---|---|---|---|
| Operating revenues | **$ 1,799** | **$ 1,495** | **$ 1,423** | **$ 1,807** | $ 1,473 | $ 1,427 | $ 1,469 | $ 1,857 |
| Net income (loss) attributable to common shareholders | **231** | **118** | **90** | **271** | (228) | 81 | 101 | 312 |
| Adjusted net income attributable to common shareholders | **167** | **191** | **111** | **202** | 137 | 118 | 117 | 152 |
| Earnings per common share – basic | **0.98** | **0.51** | **0.38** | **1.17** | (1.06) | 0.38 | 0.47 | 1.48 |
| Earnings per common share – diluted | **0.98** | **0.50** | **0.38** | **1.17** | (1.06) | 0.38 | 0.47 | 1.47 |
| Adjusted earnings per common share – basic | **0.71** | **0.82** | **0.48** | **0.87** | 0.64 | 0.55 | 0.55 | 0.72 |

Quarterly operating revenues and adjusted net income attributable to common shareholders are affected by seasonality. The first quarter provides strong earnings contributions due to a significant portion of the Company's operations being in northeastern North America, where winter is the peak electricity usage season. The third quarter provides strong earnings contributions due to summer being the heaviest electric consumption season in Florida. 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 also be affected by items outlined in the "Significant Items Affecting Earnings" section and mark-to-market adjustments.