Management's Discussion & Analysis

As at February 9, 2018

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 2017 relative to the same quarter in 2016; the full year of 2017 relative to 2016 and selected financial information for 2015; and its financial position as at December 31, 2017 relative to December 31, 2016. 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 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.

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, 2017. 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
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
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; capital market and liquidity risk; future dividend growth; timing and costs associated with certain capital projects; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; weather; commodity price risk; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; credit risk; commercial relationship risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; market energy sales prices; labour relations; and availability of labour and management resources.

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

INTRODUCTION AND STRATEGIC OVERVIEW

Emera is a geographically diverse energy and services company. The Company has investments in electricity generation, transmission and distribution and gas transmission and distribution, predominantly within rate-regulated utilities which support strong, consistent earnings and cash flow. Emera seeks to provide its customers with reliable, cost-effective and sustainable energy products and services, and provides regional energy solutions by connecting its assets, markets and partners in Canada, the United States and the Caribbean.

For investors, Emera seeks to deliver consistent earnings, cash flow and long-term growth, and accordingly, the primary measures of performance are annual dividend growth, earnings per common share growth, adjusted earnings per common share growth (a non-GAAP measure described in the Non-GAAP Financial Measures section below) and total shareholder return. The Company targets eight per cent annual dividend growth through 2020. Emera targets achieving a minimum of 75 per cent of its adjusted net income from its rate-regulated utilities and an average dividend payout ratio of 70 to 75 per cent of adjusted net income.

For the	Year ended December 31, 2017		
	1 year	3 year	5 year
Dividend per share compound annual growth rate	6.5%	12.9%	9.4%
Earnings per share compound annual growth rate	(6.0%)	(23.9%)	(6.7%)
Adjusted earnings per share compound annual growth rate (see Non-GAAP Financial Measures below)	(11.2%)	3.3%	5.9%
Emera annualized total shareholder return (1)	8.3%	11.2%	11.0%
S&P/TSX Capped Utilities Index annualized total shareholder return (2)	10.7%	7.6%	7.0%

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

Energy markets worldwide, in particular across North America, are undergoing foundational changes that have created significant investment opportunities for companies with Emera's experience and capabilities. Key trends contributing to these investment opportunities include: aging infrastructure, lower-cost natural gas, growing demand for new electric heating and cooling solutions, the requirement for large-scale transmission projects to deliver new energy sources to customers, technological developments, and environmental concerns. These environmental concerns include a desire to reduce emissions of carbon dioxide and other greenhouse gases and the potential system impacts of climate change, including changes in global and regional weather patterns, changes in the frequency and intensity of extreme weather events, and rising sea levels. At the core of Emera's utilities strategy is identifying opportunities to invest in the transition from higher-carbon methods of electricity generation to lower-carbon alternatives, and the related transmission and distribution infrastructure to deliver that energy to market.

The energy sector continues to be impacted by mandated and incented carbon reductions throughout eastern North America and in the Caribbean. It is unclear whether economic volatility, government policy and lower fossil fuel prices will slow the pace of this change in the industry. Investment in wind, solar, and hydro generation, natural gas and new transmission infrastructure is likely to continue across the sector despite any cost differential with more carbon-intensive generating options. The capital spending requirements related to these investments will need to be managed within the context of overall energy pricing.

In Florida, the Company is evaluating and investing in a number of initiatives, including solar generation, that would reduce carbon emissions. In Nova Scotia, the Company has invested in wind energy, biomass and hydroelectricity and is on track to meet a minimum 40 per cent renewable standard by 2020. In the Caribbean, Emera is similarly focused on introducing cleaner generation alternatives, with an emphasis on affordability and fuel cost stability for its customers.

Emera is investing in electricity transmission to deliver new renewable energy to market. Emera's ownership in the Maritime Link and Labrador Island Link projects will contribute to the transformation of the electricity market in the Atlantic provinces, enabling growth in the availability of clean, renewable energy for the region. In addition, the Atlantic provinces will benefit from enhanced connection to the northeastern United States, providing potential for excess renewable energy to be delivered throughout that region.

Emera Energy is a physical energy marketing and trading business, complemented by a portfolio of competitive electricity generation facilities. A substantial portion of Emera Energy's activities are in northeastern North America, and its market knowledge, focus on customer service and robust risk management are key success factors. Unlike the vast majority of Emera's businesses, Emera Energy is not rate-regulated.

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

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

Emera has grown its asset base to deliver on its strategic objectives. Over the last 10 years, Emera's ability to raise the capital necessary to fund investments has been a strong enabler of the Company's growth. In addition to access to debt and equity capital markets, cash flow from operations will continue to play a role in financing the Company's future growth. Maintaining strong, investment grade credit ratings is an important component of Emera's financing strategy.

The energy industry is seasonal in nature. Seasonal patterns and other weather events, including the number and severity of storms, can affect demand for energy and cost of service. Similarly, mark-to-market adjustments and foreign currency exchange can have a material impact on the financial results for a specific period. Results in any one quarter are not necessarily indicative of results in any other quarter, or for the year as a whole.

The effect of foreign currency exchange on Emera's net income is noteworthy, as it is expected that approximately 70 per cent of Emera's adjusted net income will be derived from subsidiaries with a US functional currency. Emera's consolidated net income and cash flows will be impacted by movements in the US dollar relative to the Canadian dollar. In general, Emera benefits from a weakening Canadian dollar and is adversely impacted by a strengthening Canadian dollar.

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 MTM adjustments and the impact in 2017 of US tax reform, signed into legislation on December 22, 2017 in the US Tax Cuts and Jobs Act of 2017 ("the Act") (refer to the "Developments" section for further details).

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;

- the mark-to-market adjustments included in Emera's other income in 2016 related to the effect of USD-denominated currency and forward contracts for the TECO Energy, Inc. ("TECO Energy") acquisition. These contracts were put in place to economically hedge the anticipated proceeds from the 2015 sale of $2.185 billion four-per-cent convertible unsecured subordinated debentures represented by instalment receipts ("the Debenture Offering" or "Debentures" or "Convertible Debentures").

The US Tax reform adjustment is a result of the estimated revaluation of US non-regulated net deferred income tax assets as a result of the US federal corporate income tax rate reduction from 35 per cent to 21 per cent that was enacted in December 2017.

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

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

Due to the enactment of the US Tax Cuts and Jobs Act of 2017, the Company recorded a non-cash income tax expense resulting from the provisional revaluation of the existing US non-regulated net deferred income tax assets. This provisional 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 provisional revaluation better distinguishes the ongoing operations of the business, and allows investors to better understand and evaluate the Company. The impact of US tax reform is further discussed in the "Developments" section.

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 millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2017	2016	**2017**	2016	2015
Net income (loss) attributable to common shareholders	**$ (228)**	$ 70	**$ 266**	$ 227	$ 397
Revaluation of US non-regulated deferred income taxes	**$ (317)**	$ -	**$ (317)**	$ -	$ -
After-tax mark-to-market gain (loss)	**$ (48)**	$ (34)	**$ 59**	$ (248)	$ 67
Adjusted net income attributable to common shareholders	**$ 137**	$ 104	**$ 524**	$ 475	$ 330
Earnings per common share – basic	**$ (1.06)**	$ 0.34	**$ 1.25**	$ 1.33	$ 2.72
Adjusted earnings per common share – basic	**$ 0.64**	$ **0.51**	**$ 2.46**	$ 2.77	$ 2.26

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 to assess 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 the EBITDA measures of other companies but in management's view appropriately reflects 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.

EBITDA and Adjusted EBITDA are discussed further in the Consolidated Financial Review, Emera Florida and New Mexico, NSPI, Emera Maine, Emera Caribbean, Emera Energy, and Corporate and Other sections.

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

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2017	2016	**2017**	2016	2015
Net income (loss) (1)	**$ (232)**	$ 71	**$ 299**	$ 266	$ 452
Interest expense, net	**175**	169	**698**	585	212
Income tax expense (recovery)	**329**	(6)	**520**	(22)	93
Depreciation and amortization	**212**	212	**856**	588	340
EBITDA	**484**	446	**2,373**	1,417	1,097
Mark-to-market gain (loss), excluding income tax and interest	**(75)**	(52)	**78**	(327)	66
Adjusted EBITDA	**$ 559**	$ 498	**$ 2,295**	$ 1,744	$ 1,031

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

2017

US Tax Reform

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the "Act") was signed into legislation. As a result of this legislation being enacted during 2017, the Company is required to revalue its US deferred income tax assets and liabilities based on the new 21 per cent tax rate. The Company has recognized an estimated $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 allows for an offsetting regulatory liability. Refer to the "Developments" section for further details.

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

After-tax mark-to-market losses increased $14 million to $48 million in Q4 2017 compared to $34 million in Q4 2016 mainly due to changes in existing positions on contracts at Emera Energy. Year-to-date, after-tax mark-to-market increased $307 million to a $59 million gain in 2017 compared to a $248 million loss for the same period in 2016. 2016 year-to-date included a $116 million loss resulting from the reversal of 2015 gains on USD-denominated currency and forward contracts related to the financing of the TECO Energy acquisition. Other factors contributing to the increase include changes in existing positions on long-term contracts at Emera Energy, and the reversal of 2016 mark-to-market losses at Emera Energy.

2016

Acquisition Related Costs

Emera incurred after-tax costs of $166 million ($0.97 per common share) in 2016 related to its acquisition of TECO Energy. All acquisition costs were recognized in the Corporate and Other segment.

Investment in Algonquin Power and Utilities Corp.

On December 8, 2016, Emera completed the sale of 12.9 million common shares of Algonquin Power and Utilities Corp ("APUC"), representing approximately 4.7 per cent of APUC's issued and outstanding common shares, for gross proceeds of $142 million. This sale resulted in a pre-tax loss of $12 million or $0.07 per common share (after-tax loss of $10 million or $0.06 per common share), which was recorded in "Other income (expenses), net" in Q4 2016. Emera no longer holds any interest in APUC.

On June 30, 2016, Emera exchanged 12.9 million APUC subscription receipts and dividend equivalents into 12.9 million APUC common shares. This conversion resulted in a pre-tax gain of $63 million or $0.42 per common share (after-tax gain of $53 million or $0.35 per common share), which was recorded in "Other income (expenses), net" in Q2 2016.

On May 24, 2016, Emera completed the sale of 50.1 million common shares of APUC, representing approximately 19.3 per cent of APUC's issued and outstanding common shares, for gross proceeds of $544 million. This sale resulted in a pre-tax gain of $172 million or $1.15 per common share (after-tax gain of $146 million or $0.97 per common share), which was recorded in "Other income (expenses), net" in Q2 2016.

Gain on BLPC Self-Insurance Fund Regulatory Liability

BLPC maintains a Self-Insurance Fund ("SIF") for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC's generating, transmission and distribution systems. Third-party risk advisors were engaged to support a detailed risk analysis, which was completed to quantify the prudent assessment of the risk to BLPC's transmission and distribution system from natural catastrophes.

In June 2016, BLPC secured support from the Government of Barbados and the Trustees of the SIF to reduce the contingency funding in the SIF to $29 million ($22 million USD). As a result, Emera recorded a pre-tax gain of $53 million ($41 million USD) or $0.35 per common share and an after-tax gain of $43 million ($34 million USD) or $0.29 per common share in "Other income (expenses), net". In Q3 2016, Emera received a distribution of $65 million ($50 million USD) from the fund.

Emera Energy Recognition of State Fuel Taxes

In Q2 2016, Emera Energy recorded a $20 million pre-tax or $0.13 per common share ($12 million after-tax or $0.08 per common share) liability for state tax on natural gas sales made from November 2013 through March 2016, including $4 million pre-tax ($2 million after-tax) related to Q1 2016. The recognition of this liability resulted in an increase to "Non-regulated fuel for generation and purchased power".

Consolidated Financial Highlights

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
Adjusted Net Income	**2017**	2016	**2017**	2016	2015
Emera Florida and New Mexico	**$ 80**	$ 63	**$ 382**	$ 172	$ -
NSPI	**23**	34	**129**	130	130
Emera Maine	**8**	11	**46**	47	45
Emera Caribbean	**1**	8	**31**	100	41
Emera Energy	**26**	5	**24**	24	130
Corporate and Other	**(1)**	(17)	**(88)**	2	(16)
Adjusted net income attributable to common shareholders	**$ 137**	$ 104	**$ 524**	$ 475	$ 330
Revaluation of US non-regulated deferred income taxes	**(317)**	-	**(317)**	-	-
After-tax mark-to-market gain (loss)	**(48)**	(34)	**59**	(248)	67
Net income (loss) attributable to common shareholders	**$ (228)**	$ 70	**$ 266**	$ 227	$ 397

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2017	2016	**2017**	2016	2015
Operating revenues	**$ 1,473**	$ 1,513	**$ 6,226**	$ 4,277	$ 2,789
Income from operations	**236**	208	**1,391**	555	508
Net income (loss) attributable to common shareholders	**(228)**	70	**266**	227	397
Revaluation of US non-regulated deferred income taxes	**(317)**	-	**(317)**	-	-
After-tax mark-to-market gain (loss)	**(48)**	(34)	**59**	(248)	67
Adjusted net income attributable to common shareholders	**$ 137**	$ 104	**$ 524**	$ 475	$ 330
Earnings per common share – basic	**$ (1.06)**	$ 0.34	**$ 1.25**	$ 1.33	$ 2.72
Earnings per common share – diluted	**$ (1.06)**	$ 0.34	**$ 1.24**	$ 1.32	$ 2.71
Adjusted earnings per common share – basic	**$ 0.64**	$ 0.51	**$ 2.46**	$ 2.77	$ 2.26
Dividends per common share declared	**$ -**	$ -	**$ 2.1325**	$ 1.9950	$ 1.6625
Adjusted EBITDA	**$ 559**	$ 498	**$ 2,295**	$ 1,744	$ 1,031

The following table highlights the significant changes in adjusted net income from 2016 to 2017:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2016	**$ 104**	**$ 475**
Emera Florida and New Mexico	17	210
2016 acquisition and financing costs related to the acquisition of TECO Energy	(13)	166
NSPML and LIL AFUDC earnings	6	28
2016 Emera Energy's recognition of fuel taxes for 2013 to March 2016	-	12
NSPI	(11)	(1)
Emera Energy	21	(12)
APUC equity earnings - sold in 2016	-	(18)
Emera Caribbean	(7)	(26)
2016 gain on BLPC SIF regulatory liability	-	(43)
2016 gain on conversion of APUC subscription receipts and dividend equivalents to common shares of APUC	-	(53)
TECO Energy post-acquisition financing costs	-	(83)
2016 gain/loss on sale of APUC common shares	10	(136)
Other	10	5
Adjusted net income – 2017	**$ 137**	**$ 524**

For the millions of Canadian dollars						Year ended December 31
		2017		2016		2015
Operating cash flow before changes in working capital	**$**	**1,297**	$	919	$	776
Change in working capital		**(104)**		134		(102)
Operating cash flow	**$**	**1,193**	$	1,053	$	674
Investing cash flow (1)	**$**	**(1,761)**	$	(9,037)	$	(124)
Financing cash flow	**$**	**593**	$	7,448	$	221

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

As at						December 31
millions of Canadian dollars		**2017**		2016		2015
Total assets	**$**	**28,771**	$	29,221	$	12,039
Total long-term debt (including current portion)	**$**	**13,881**	$	14,744	$	4,009

Q4 Consolidated Income Statement Highlights

Operational Results

Income from operations increased $28 million to $236 million in Q4 2017 compared to $208 million in the same quarter in 2016. Absent mark-to-market losses of $23 million, income from operations increased $51 million due to increased contributions from Emera Florida and New Mexico and Emera Energy.

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

Total operating revenues decreased $40 million to $1,473 million in Q4 2017 compared to $1,513 million in Q4 2016. Absent mark-to-market losses of $13 million, operating revenues decreased $27 million due to:

- $17 million decrease from Emera Florida and New Mexico reflecting the impact of a stronger CAD. This decrease was partially offset by increased revenues at Tampa Electric reflecting customer growth and higher base rates offset by lower clause-related revenues;
- $10 million decrease from EUS reflecting decreased project activity.

Total operating expenses decreased $68 million to $1,237 million in Q4 2017 compared to $1,305 million in Q4 2016. This is primarily due to the impact of a stronger CAD, lower operating, maintenance and general ("OM&G") at Emera Florida and New Mexico reflecting lower generation outage and maintenance costs, lower fuel expense at Tampa Electric and decreased natural gas purchases at Bayside Power reflecting the renegotiation of the Bayside Power PPA for the winter of 2017/2018.

Income tax expense (recovery)

Income tax expense increased $335 million to a $329 million expense in Q4 2017 compared to a $6 million recovery for the same period in 2016 primarily due to the estimated impact of the enacted US federal corporate income tax rate reduction from US tax reform (refer to "Developments" section for further details) and increased income before provision for income taxes.

2017 Consolidated Income Statement and Operating Cash Flow Highlights

Operational Results

Income from operations increased $836 million to $1,391 million for the year ended December 31, 2017 compared to $555 million in 2016. Absent mark-to-market increases of $267 million, income from operations increased $569 million mainly due to the contribution of Emera Florida and New Mexico for the full year of 2017 and the 2016 costs related to the acquisition of TECO Energy.

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

Total operating revenues increased $1,949 million to $6,226 million for the year ended December 31, 2017 compared to $4,277 million in the same period in 2016. Absent mark-to-market increases of $285 million, operating revenues increased $1,664 million due to:

- $1,784 million increase from Emera Florida and New Mexico as 2017 includes a full year of revenues;
- $115 million decrease at Emera Energy Generation ("EEG") reflecting lower hedged power prices in Q1 2017 compared to Q1 2016, decreased sales volumes driven by an unplanned outage at the Bridgeport Facility and less favourable market conditions in 2017. This decrease was partially offset by higher capacity revenue that came into effect for New England Gas Generating Facilities ("NEGG") in June 2017.

Total operating expenses increased $1,113 million to $4,835 million for the year ended December 31, 2017 compared to $3,722 million in 2016, primarily due to:

- $1,285 million increase from Emera Florida and New Mexico as 2017 includes a full year of expenses;
- $116 million decrease in fuel expense at EEG due to decreased sales volumes reflecting an unplanned outage at the Bridgeport Facility, lower hedged natural gas prices in Q1 2017 compared to Q1 2016, the recognition of prior period state fuel taxes in Q2 2016 and less favourable market conditions in 2017;
- $99 million decrease related to the 2016 TECO Energy acquisition costs.

Other income (expenses), net

Other income decreased $172 million to $2 million for the year ended December 31, 2017 compared to $174 million in the same period in 2016. This was due to a $160 million gain on the 2016 sale of APUC common shares, a $63 million gain on the 2016 conversion of APUC subscription receipts and dividend equivalents into common shares, and a $53 million gain on the BLPC SIF regulatory liability in 2016. These 2016 gains were partially offset by $134 million of mark-to-market losses in 2016 relating to the TECO Energy acquisition related USD-denominated currency and forward contracts.

Interest expense, net

Interest expense, net increased $113 million for the year ended December 31, 2017 to $698 million compared to $585 million in 2016. This was due to interest expense from Emera Florida and New Mexico and financing related to the TECO Energy acquisition, partially offset by the interest and Beneficial Conversion Feature costs associated with the TECO Energy acquisition related Debentures in Q3 2016.

Income tax expense (recovery)

Income tax expense increased $542 million to a $520 million expense for the year ended December 31, 2017 compared to a $22 million recovery in 2016 primarily due to the estimated impact of the enacted US federal corporate income tax rate reduction, increased income before provision for income taxes and the non-taxable portion of gains on 2016 APUC transactions. This was partially offset by the non-deductible portion of foreign exchange and mark-to-market adjustments related to the TECO Energy acquisition in 2016.

Net cash provided by operating activities

Net cash provided by operating activities in 2017 increased $140 million to $1,193 million compared to $1,053 million during the same period in 2016.

Cash from operations before changes in working capital increased $378 million mainly due to the full year contribution from Emera Florida and New Mexico and acquisition and financing costs related to the TECO Energy acquisition in 2016, partially offset by increased financing costs in 2017 and decreases from Emera Energy.

Changes in working capital decreased operating cash flows by $238 million. This decrease was due to higher receivables at TEC as a result of higher sales, unfavourable changes in inventory, accounts payable and other current liabilities at NSPI compared to 2016 and refunds to customers in 2017 for fuel clause over-recoveries collected in 2016 at TEC.

Effect of Foreign Currency Translation

Emera operates globally, 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/US exchange rates for 2017 and 2016 are as follows:

	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
Weighted average CAD/USD exchange rate	**$ 1.27**	$ 1.32	**$ 1.30**	$ 1.32
Period end CAD/USD exchange rate	**$ 1.25**	$ 1.34	**$ 1.25**	$ 1.34

Changes in foreign exchange, due primarily to the strengthening of the CAD, decreased losses by $11 million and decreased adjusted earnings by $5 million in Q4 2017 compared to Q4 2016. The strengthening of the CAD decreased earnings by $5 million and adjusted earnings by $10 million in 2017 compared to 2016.

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	
	2017	2016	**2017**	2016
Emera Florida and New Mexico	**$ 63**	$ 47	**$ 295**	$ 131
Emera Maine	**7**	9	**36**	36
Emera Caribbean	**1**	6	**24**	77
Emera Energy (1)	**8**	5	**15**	25
	79	67	**370**	269
Corporate and Other (2)	**(29)**	(29)	**(116)**	(59)
Total (3)	**$ 50**	$ 38	**$ 254**	$ 210

(1) Includes Emera Energy's US dollar adjusted net income from Emera Energy Services, 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 marked-to-market or tax reform.

BUSINESS OVERVIEW AND OUTLOOK

Emera Florida and New Mexico

Emera Florida and New Mexico includes the following:

- TECO Energy, the parent of the companies discussed below.
- TEC, which 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 for residential, commercial, industrial and electric power generation customers in Florida.
- NMGC, a regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas for residential, commercial and industrial customers in New Mexico.
- TECO Finance, a financing subsidiary of TECO Energy.

Tampa Electric

With nearly $7.2 billion USD of assets and approximately 750,000 customers at December 31, 2017, Tampa Electric owns 5,218 megawatts ("MW") of generating capacity, of which 64 per cent is natural gas-fired, 31 per cent is conventional coal-fired, 4 per cent coal and petroleum coke ("petcoke") and 1 per cent solar. Tampa Electric owns 2,140 kilometres of transmission facilities and 18,550 kilometres of distribution facilities.

Tampa Electric's target regulated return on equity ("ROE") range is 9.25 per cent to 11.25 per cent, 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 more than $1.2 billion USD of assets and approximately 375,000 customers, the PGS system includes approximately 20,380 kilometres of natural gas mains and 11,550 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 1.8 billion therms in 2017.

The allowed ROE range for PGS is 9.25 per cent to 11.75 per cent, 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 $0.9 billion USD of assets and approximately 525,000 customers, NMGC serves about 60 per cent of the state's population in 23 of New Mexico's 33 counties. NMGC's system includes approximately 2,650 kilometres of transmission lines and 16,670 kilometres of mains. Annual natural gas throughput is approximately 750 million therms.

The allowed 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. Under the Order, NMGC will also provide customer credits of $4 million USD annually through June 30, 2018. NMGC expects to file a rate case in 2018 with new rates effective approximately twelve months after filing, subject to NMPRC approval.

Emera Florida and New Mexico Outlook

Emera Florida and New Mexico earnings are most directly impacted by the rate of return on equity and the capital structures approved by the FPSC and NMPRC, the prudent management of operating costs, the approved recovery of regulatory deferrals, weather and its impact on energy demand and the timing and amount of capital expenditures.

The Florida utilities anticipate earning within their allowed ROE ranges in 2018 and expect rate base and earnings to be higher than prior years. Tampa Electric expects customer growth rates in 2018 to be in line with 2017, reflective of economic growth in Florida. PGS expects customer growth rates in 2018 to be higher than 2017, reflective of economic growth in Florida and the optimization of existing gas main opportunities. Assuming normal weather, sales volumes are expected to increase consistent with customer growth.

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. A settlement agreement was filed with the FPSC requesting a base rate adjustment that provides for the recovery, upon in-service, of up to 600 MW of investments in utility-scale solar projects that will be phased in from late 2018 through early 2021. On November 6, 2017, the FPSC approved the settlement agreement. On December 12, 2017 Tampa Electric filed its petition along with supporting tariffs demonstrating the cost-effectiveness of the September 1, 2018 solar base rate adjustment ("SoBRA") representing 145 MW and $26 million in estimated revenue requirements. A decision by the FPSC to approve the tariffs on the first SoBRA filing is anticipated in the spring of 2018. Refer to "Developments" for further details.

In September 2017, Tampa Electric was impacted by Hurricane Irma. The majority of Hurricane Irma restoration costs will be charged against Tampa Electric's FPSC approved storm reserve, resulting in minimal impact on 2017 earnings. Estimated total restoration costs are $105 million USD with $93 million USD charged to the storm reserve, $8 million USD charged to capital expenditures and $4 million USD in OM&G expense. The increase in estimated storm costs from the $70 million estimated at the end of Q3 2017 is due to higher than expected mutual assistance and contractor costs. Tampa Electric petitioned the FPSC on December 28, 2017 for recovery of estimated restoration costs in excess of the reserve for several named storms including Hurricane Irma and to replenish the balance in the reserve to the $56 million USD level that existed as of October 31, 2013. An amended petition was filed with the FPSC on January 30, 2018.

On December 22, 2017, tax reform changes were signed into legislation. It is expected there will be no material change in Tampa Electric, PGS or NMGC earnings as the reduction in the federal income tax rate will be offset by lower customer rates over time and the revaluation of the existing net deferred tax liabilities, were offset with a regulatory liability, which will be returned to customers over time. The Tampa Electric solar settlement agreement provides for the impacts of tax reform to be offset by a reduction in base revenues through the adjustment of customer rates within 120 days of when tax reform became law. PGS and NMGC will address the impacts of tax reform through their normal regulatory process. On January 9, 2018, the Florida Office of Public Counsel ("OPC") filed a petition with the FPSC requesting the FPSC to adjust rates for all utilities in Florida to reflect the reduction in the tax rate.

On January 30, 2018, Tampa Electric filed with the FPSC a settlement agreement which, if approved, will allow Tampa Electric to net the estimated amount of storm cost recovery against the utility's estimated 2018 tax reform benefits. Any difference would be trued up and recovered from or returned to customers in 2019. Beginning in January 2019 Tampa Electric would reflect the full impact of tax reform on Tampa Electric's base rates, provided that the FPSC's determinations have been finalized. A decision is expected in March 2018.

NMGC expects earnings to be consistent with prior years. Customer growth rates are expected to be consistent with 2017, reflecting expectations for housing starts and new connections. NMGC plans to file a rate case in 2018.

In 2018, Emera Florida and New Mexico expects to invest approximately $1.3 billion USD, including allowance for funds used during construction ("AFUDC"), in capital projects compared to $700 million USD in 2017. Capital projects support normal system reliability and growth at the three utilities, including capital projects at Tampa Electric for transmission and distribution storm hardening. The increase over 2017 is primarily due to significant investment in the solar photovoltaic projects at Tampa Electric. PGS will make investments to expand its system and support customer growth, and continue with replacement of obsolete plastic, cast iron and bare steel pipe. NMGC will complete a project to relocate a portion of the gas pipeline feeding Taos, New Mexico, and will continue to invest in system improvements by replacing legacy pipe and making pipeline integrity management improvements.

NSPI

NSPI is a fully-integrated regulated electric utility and is the primary electricity supplier in Nova Scotia, Canada. NSPI has $5.0 billion of assets and provides electricity generation, transmission and distribution services to approximately 515,000 customers. The Company owns 2,488 MW of generating capacity, of which approximately 43 per cent is coal-fired; 29 per cent is natural gas and/or oil; 19 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 544 MW of capacity. This is expected to increase to 560 MW of capacity in 2018. IPP generation includes wind, tidal, biogas and biomass-fueled generation. NSPI owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities.

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

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 2018 and expects modest rate base growth which will deliver a similar modest increase in earnings.

In December 2015, the *Electricity Plan Act* was enacted by the Province of Nova Scotia with a goal of providing rate stability and predictability for customers for the 2017 through 2019 period. 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. The Company continues to work with officials at both of these levels of government to comply with these regulations in an integrated way, maximizing efficiency of emission control measures. Over the past several years, the requirement to reduce Nova Scotia's reliance upon higher carbon and greenhouse gas emitting sources of energy has resulted in NSPI making a significant investment in renewable energy sources and purchasing third party renewable energy.

In December 2016, the Government of Canada and eight provinces (including Nova Scotia) signed the Pan-Canadian Framework on Clean Growth and Climate Change. The Government of Canada has committed to ensuring that the provinces and territories have the flexibility to design their own policies and programs to meet emission-reduction targets, supported by federal investments in infrastructure, specific emission-reduction opportunities and clean technologies. Nova Scotia and the Government of Canada will establish a new equivalency agreement that will enable the province to move from fossil fuels to clean energy sources and enable NSPI's coal-fired plants to operate at some capacity beyond 2030. NSPI anticipates that any costs prudently incurred to achieve the legislated reductions will be recoverable from customers under NSPI's regulatory framework. The future earnings impact of the carbon emission reduction strategy being developed from the Pan-Canadian Framework on Clean Growth and Climate Change is unknown.

In October 2017, the Province of Nova Scotia passed amendments to the Environment Act to enable the development of a cap-and-trade program for carbon emissions. NSPI anticipates that any costs prudently incurred to achieve the legislated reductions will be recoverable from customers under NSPI's regulatory framework. NSPI continues to work with the Province of Nova Scotia on details of the carbon emission reduction agreements and to advance solutions that are in the best interest of customers.

In September 2017, the UARB approved NSPI's interim assessment payment to NSPML of the costs associated with the Maritime Link starting when the Maritime Link is in service. The Maritime Link completed commissioning and entered service on January 15, 2018. In response to the delayed timing of energy delivery from the Muskrat Falls project, the approved interim assessment payment reflects NSPML's proposal to reduce the assessment by deferring $53 million in each of 2018 and 2019, related to depreciation and amortization expenses. As these amounts are included in NSPI's 2017, 2018 and 2019 fuel rates and are being recovered from customers, NSPI will provide a one-time credit to customers, including interest, in 2018 of approximately $17 million, in 2019 of approximately $36 million and in 2020 of approximately $53 million of these recoveries from customers, as the payments from NSPI to NSPML are not required in those years.

NSPI is also required to hold back $10 million from the interim assessment payment to NSPML in each of 2018 and 2019. The release of such amounts is subject to providing evidence to the UARB that at least that amount of benefit from the Maritime Link has been realized for NSPI customers in that year. If the $10 million in benefits is realized, the UARB will direct NSPI to pay the $10 million to NSPML for that year. If not realized, then the UARB will direct NSPI to pay to NSPML only that portion that is realized and the balance will be refunded to customers through NSPI's Fuel Adjustment Mechanism ("FAM").

In 2018, NSPI expects to invest approximately $360 million, including AFUDC, in capital projects compared to $392 million in 2017. Capital will primarily be invested in projects which will support normal system reliability, with the decrease from 2017 driven by a reduction in spending on information technology and transmission projects.

Emera Maine

Emera Maine is a transmission and distribution ("T&D") electric utility with assets of approximately $1.2 billion serving approximately 158,000 customers in the State of Maine. Emera Maine owns and operates approximately 1,800 kilometres of transmission facilities and 15,000 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 54 per cent of Emera Maine's electric revenue represents distribution operations, 33 per cent is associated with local transmission operations and 13 per cent relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

Emera Maine's earnings are most directly impacted by the range of rates of ROE and rate base approved by its regulators, the prudent management and approved recovery of operating costs, load (including the effects of weather), and the timing and amount of capital expenditures.

Emera Maine's 2018 rate base is expected to grow modestly due to ongoing investment in transmission and distribution infrastructure, resulting in modest growth in earnings.

On December 22, 2017, tax reform changes were signed into legislation. It is expected there will be no material change in Emera Maine's earnings as the reduction in the federal income tax rate will be offset by lower customer rates. The revaluation of the existing net deferred tax liabilities, at the new tax rate, were offset with a regulatory liability that will be returned to customers over time. Emera Maine will address the impacts of tax reform through their normal regulatory process.

There are currently four pending complaints filed with the FERC to challenge the ISO-New England ("ISO-NE") Open Access Transmission Tariff-allowed based ROE. On June 19, 2014, in connection with the first complaint, the FERC set the base ROE at 10.57 per cent and capped the total ROE, including the effect of incentive adders, at 11.74 per cent. On April 14, 2017, the U.S. Court of Appeals for the District of Columbia Circuit vacated this order and remanded the case to the FERC for further proceedings. No changes in reserves have been made as a result of the Court of Appeals vacating the FERC Order, as the outcome is considered uncertain. A decision on the second and third complaints is expected in 2018. For further discussion on the complaints, see note 27 to the consolidated financial statements for the year ended December 31, 2017.

In 2018, Emera Maine expects to invest approximately $70 million USD (2017 – $61 million USD), primarily on transmission and distribution capital projects.

Emera Caribbean

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

Consolidated Investments

- 100.0 per cent investment in ECI and its wholly owned subsidiary BLPC, a vertically integrated utility that is the provider of electricity in Barbados. BLPC serves 129,000 customers. BLPC owns 239 MW of oil-fired generation, 150 kilometres of transmission facilities and 2,800 kilometres of distribution facilities. BLPC's approved regulated return on rate base for 2017 is 10.0 per cent.

- 50.0 per cent direct and 30.4 per cent indirect interest (through a 60.7 per cent interest in ICD Utilities Limited ("ICDU")) in GBPC, a vertically integrated utility and the sole provider of electricity on Grand Bahama Island. GBPC serves 19,000 customers. GBPC owns 98 MW of oil-fired generation, 138 kilometres of transmission facilities and 860 kilometres of distribution facilities. In December 2017, the GBPA approved GBPC's regulated return on rate base of 8.5 per cent for 2018. On November 8, 2017, the minority shareholders of ICD Utilities Limited approved Emera's acquisition of their common shares for total consideration of approximately $35 million USD. The acquisition of the minority shareholder common shares was completed on January 15, 2018, increasing Emera's ownership interest in GBPC to 100 per cent.

- 51.9 per cent indirect controlling interest, through ECI, in Domlec, an integrated utility on the island of Dominica. Domlec serves 36,000 customers. Domlec owns 20 MW of oil-fired generation, 7 MW of hydro production, 497 kilometres of transmission facilities and 716 kilometres of distribution facilities. On September 19, 2017 Dominica took a direct hit from Hurricane Maria, a category 5 hurricane. Refer to the "Developments" section for further details. Domlec's approved allowable regulated return on rate base for 2017 is 15.0 per cent.

Equity Investment

- 19.1 per cent indirect interest, through ECI, in Lucelec, a vertically integrated regulated electric utility on the island of St. Lucia. The investment in Lucelec is accounted for on the equity basis.

Earnings from Emera Caribbean are most directly impacted by the rates of return on rate base approved by their regulators, capital structure, prudent management and approved recovery of operating costs, sales volumes, and the timing and scale of capital expenditures.

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, BLPC commissioned a 10 megawatt solar facility in Barbados, which became operational in 2016. Additional renewable energy generation investments are being developed.

On May 30, 2017, the Minister of Finance in Barbados delivered a new budget. Key measures include an increase in the National Social Responsibility Levy ("NSRL") from two per cent to 10 per cent and the introduction of a two per cent foreign exchange commission, both effective July 1, 2017. The NSRL is charged on all goods imported into Barbados and on domestically manufactured goods. The impact of these immaterial changes is incorporated into BLPC's cost of service.

The 2017 Atlantic hurricane season was active. The island of Grand Bahama was impacted by Hurricane Irma, however there was minimal damage to the system as a result of the storm. The island of Dominica took a direct hit from Maria, a Category 5 hurricane. Emera's total investment in Domlec is $7 million USD. The Company has implemented a restoration plan and expects to have all main circuits energized and the system ready to connect customers who are ready and certified to be connected in 2018. Refer to the "Developments" section for further details about Domlec and the impact of Hurricane Maria. Barbados was not been affected by any hurricanes in 2017.

Overall, Emera Caribbean 2018 earnings are expected to increase over the prior year. Earnings from GBPC are expected to increase due to recovering load after the short term decline from Hurricane Matthew in 2016. Domlec is expecting a loss for 2018 consistent with 2017, as it continues to execute its restoration plan from Hurricane Maria. The increase at GBPC will be partially offset by lower earnings in 2018 from BLPC due to increased interest expense as the utility rebalances its capital structure.

Emera Caribbean plans to invest approximately $85 million USD in capital programs in 2018 (2017 - $54 million USD). This increase is due to spending on transmission, battery storage, renewable generation and LED street lighting projects.

Emera Energy

Emera Energy includes the following:

- 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 with 1,435 megawatts ("MW") of total capacity.
- Equity investment in a 50.0 per cent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts. The investment in Bear Swamp is accounted for on an equity basis.

Emera Energy Services

Earnings from Emera Energy Services, Emera Energy's marketing and trading business, 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.

Planned investment by the industry in gas transportation infrastructure within the northeast United States over the next few years could reduce the degree of volatility recently experienced in the market, all other things being equal.

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

The Energy Services business is generally expected to deliver net earnings of $15 to $30 million USD, with the opportunity for upside when market conditions present.

Emera Energy Generation

Earnings from Emera Energy Generation's assets are largely dependent on market conditions, in particular, the relative pricing of electricity and natural gas and the absolute price of natural gas as the marginal fuel in the supply stack, and capacity pricing in ISO-NE for the NEGG Facilities. Efficient operations of the fleet to ensure unit availability, cost management and effective commercial performance are key success factors.

Adjusted earnings from Emera Energy's generating assets in 2018 are expected to benefit from higher capacity prices and fewer outage days, all other things being equal.

Capacity Payment

In addition to energy margins and ancillary revenue, the NEGG Facilities and Bear Swamp earn revenue from capacity payments through the ISO-NE forward capacity market ("FCM"), the annual reconfiguration capacity market and the monthly reconfiguration capacity market. Prices for the FCM, the largest of the components, are determined through an auction process held annually, three years in advance, thus currently providing revenue visibility to 2022, presuming the facilities continue to be available to support their capacity obligations. Details of pricing and estimated revenues are outlined in the table below for the NEGG Facilities, and Emera Energy's 50.0 per cent interest in Bear Swamp.

Forward Capacity Auction ("FCA") Year	Clearing Price in $/kW-month (in USD)	Approximate Estimated Annual Capacity Revenue (in USD) (1)
FCA 8 (June 2017 to May 2018)	$7.03	$100 million
FCA 9 (June 2018 to May 2019)	$9.55 and $11.08 (1)	$145 million
FCA 10 (June 2019 to May 2020)	$7.03	$106 million
FCA 11 (June 2020 to May 2021)	$5.30	$80 million
FCA 12 (June 2021 to May 2022)	$4.63	$71 million

(1) $11.08 was awarded for the Southeast Massachusetts/Rhode Island zone only and, as such, applies only to Tiverton.

In 2018, Emera Energy expects to invest approximately $50 million (2017 – $47 million) in capital projects related to its generating assets to continue to improve reliability.

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 is an NEB-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 is 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") is a utility services contractor primarily operating in Atlantic Canada.

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

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

Non-consolidated investments

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

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

    - Emera's 49.5 per cent (December 31, 2016 – 62.7 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. The investment in LIL is accounted for on the equity basis. Nalcor Energy has indicated that the project will be in service in Q2 2018.

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

Corporate and Other includes corporate financing costs, AFUDC 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 contribution to consolidated adjusted net income is expected to be higher in 2018 primarily due to increased contributions from ENL as a result of increased equity investment in the Maritime Link which entered service on January 15, 2018 (see below for further discussion on Maritime Link and Labrador Island Link) and higher tax recoveries due to the non-cash tax expense recognized in 2017 as a result of US tax reform. This is partially offset by increased interest expense on higher short term borrowing and lower income tax recoveries in 2018 as a result of the lower US tax rate. Refer to the "Developments" section for further details on US tax reform.

Corporate and Other, excluding ENL as discussed below, expects to spend approximately $40 million on property, plant and equipment in 2018 (2017 - $21 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 the development of the Maritime Link Project. Project to date, ENL has invested $510 million in equity, comprised of $420 million in equity contributed and $90 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.

Through the construction period, including 2017, earnings were derived through AFUDC on invested equity, capitalized at an annual rate of 9 per cent. In September 2017, the UARB approved NSPI's interim assessment cash payment to NSPML of the costs associated with the Maritime Link starting when the Maritime Link is in service. The Maritime Link completed commissioning and entered service on January 15, 2018, enabling the transmission of electricity between Newfoundland and Labrador and Nova Scotia. In 2018, NSPML will begin operations and start earning revenue and collecting cash from NSPI. Refer to the "Developments" section for further details.

Future earnings contributions from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. The approved ROE is currently 9 per cent. Earnings are expected to be higher in 2018 than in 2017 given increased equity investment.

In 2018, ENL expects to invest approximately $15 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. As at December 31, 2017, ENL has invested $492 million in LIL, comprised of $410 million in equity and $82 million of accumulated equity earnings. 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.

Future earnings from the LIL investment are dependent on the amount and timing of additional equity investments and the approved ROE. Emera's total 2017 cash equity contributions were $55 million. The total equity contribution by Emera for the LIL is estimated to be approximately $600 million by the end of the project. No further equity contributions are forecasted until 2020.

Both the NSPML and LIL investments are recorded as equity investments - "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, 2016 and December 31, 2017 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Inventory	**(54)**	Decreased due to lower fuel inventory at NSPI as a result of lower volumes on hand and lower commodity pricing and the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Regulatory assets (current and long-term)	**54**	Increased due to an increased deferred income tax regulatory asset at NSPI and the Tampa Electric storm reserve, partially offset by the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Property, plant and equipment, net of accumulated depreciation	**(295)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries, and annual depreciation. This was partially offset by additions primarily at NSPI and Emera Florida and New Mexico.
Investments subject to significant influence	**268**	Increased due to investment in NSPML and LIL.
Goodwill	**(408)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**(583)**	Decreased due to the effect of a stronger CAD on foreign currency debt. This was partially offset by changes in the balance of credit facilities, proceeds of long-term debt at GBPC, and increased short-term debt at Emera Florida and New Mexico.
Accounts payable	**(81)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries and the timing of expenditures at TEC, partially offset by cash collateral positions on derivative instruments at NSPI, increased accruals at TEC for restoration costs after Hurricane Irma, and higher volumes and commodity prices at Emera Energy.
Deferred income tax liabilities, net of deferred income tax assets	**(674)**	Decreased due to revaluation of US deferred income tax assets and liabilities resulting from the enacted US federal corporate income tax rate reduction and the effect of stronger CAD on the translation of Emera's foreign subsidiaries. This was partially offset by increased tax deductions in excess of accounting depreciation related to property, plant and equipment.
Derivative instruments (current and long-term)	**(165)**	Decreased due to the effect of stronger CAD on foreign currency derivative instruments, the reversal of 2016 Emera Energy asset management agreements MTM losses, and changes in existing positions on long term natural gas contracts at Emera Energy.

Regulatory liabilities (current and long-term)	**829**	Increased due to the revaluation of net deferred income tax liabilities at Emera Florida and New Mexico and Emera Maine as a result of US tax reform and an increase in fuel adjustment mechanism ("FAM") regulatory liabilities at NSPI. This was partially offset with lower deferral fuel clause, accumulated cost of removal and storm reserve for TEC.
Pension and post-retirement liabilities	**(110)**	Decreased due to supplemental executive retirement plan and other post-retirement payments in Emera Florida and New Mexico and the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Common stock	**863**	Increased due to issuance of common stock including issuance of shares as part of the dividend reinvestment program.
Accumulated other comprehensive income	**(294)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Retained earnings	**(185)**	Decreased due to dividends paid in excess of net income.

DEVELOPMENTS

Share Issuance

On December 28, 2017, Emera completed an offering of 14,614,000 common shares at $47.90 per common share. The aggregate gross and net proceeds from the offering were $700 million and $680 million, respectively. The proceeds of the offering will be used to support the Company's recently announced growth initiatives and for general corporate purposes including to reduce indebtedness outstanding and to fund other ordinary course capital expenditures.

US Tax Reform

On December 22, 2017, the US Tax Cuts and Jobs Act of 2017 ("the Act") was signed into legislation, however some of the specific details have yet to be clarified. Key provisions impacting Emera are as follows:

- US federal corporate income tax rate reduction from 35 per cent to 21 per cent effective January 1, 2018.
- Interest deductibility is limited to 30 per cent of EBITDA from 2018 to 2021 and 30 per cent of EBIT after 2021. Previously, the Company was not subject to any interest deductibility limitations.
    - Regulated utilities have an exemption from this limitation allowing interest to remain deductible.
    - The Company believes that most of its US holding company interest can be properly allocable, in accordance with the Act, to its US regulated utilities and is therefore exempted from the interest deductibility limitations.
- Immediate expensing of 100 per cent of the cost of new investments made in qualified depreciable assets after September 27, 2017.
    - US regulated utilities have an exemption from this immediate expensing.
- The corporate alternative minimum tax ("AMT") is eliminated effective January 1, 2018. Existing AMT credit carryforwards can be used to offset regular federal tax liabilities with the excess being refunded. AMT credit carryforwards are fully refundable by 2022.

Impact on Emera's December 31, 2017 financial results:

- A non-cash estimated income tax expense of $317 million resulting from the provisional revaluation of the existing US non-regulated net deferred income tax assets at the lower income tax rate. This revaluation was required at the time the Act was signed and has impacted Emera's 2017 balance sheet and earnings. This adjustment has no effect on Emera's future net earnings, cash flow, credit metrics or debt covenants.
- A non-cash provisional revaluation of $1.1 billion on the existing US regulated net deferred income tax liabilities at the lower income tax rate. The Company has 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 applicable regulator. As a result, the deferred tax adjustment for the US regulated utilities has an impact on the 2017 balance sheet of Emera but no impact on 2017 earnings.

The Company is still analyzing certain aspects of the Act, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. Further adjustments, if any, will be recorded by the Company during the measurement period in 2018 as permitted by SEC Staff Accounting Bulletin 118, Income tax Accounting Implications of the Tax Cuts and Jobs Act. The Act provides that the measurement period must be completed by December 22, 2018.

Future impacts:

- Emera will experience a higher consolidated net loss from US non-regulated businesses due to a lower income tax recovery as a result of the lower tax rate that is applicable to Emera's non-regulated US businesses and its holding company interest expense. The overall impact to earnings per share is expected to be three to five per cent.
- It is expected there will be no material changes in Emera's US regulated utilities' future net earnings as a lower income tax expense and amortization of the deferred tax revaluation regulatory liability is expected to be offset by lower customer rates at Tampa Electric. The remaining US utilities will address the impact of tax reform through normal regulatory process.
- An estimated decrease in cash from operations of $50 million to $200 million annually in Emera's US businesses primarily due to expected revenue reductions as a result of lower income tax expense and amortization of the deferred tax regulatory liability at the US regulated utilities. Emera currently pays minimal cash taxes as a result of existing tax loss carryforwards and therefore the reduction in cash revenues is not offset by lower cash tax payments over the near term. This decrease will be partially offset by cash refunds associated with AMT credit carryforwards beginning in 2019. In addition, Tampa Electric has filed to collect storm restoration costs in 2018, which if approved, would offset the decrease in cash associated with tax reform in 2018.
- The Company believes that most of its US holding company interest can be properly allocable, in accordance with the Act, to its US regulated utilities and is therefore exempted from the interest deductibility limitations. As a result, there should be no impact to Emera's future earnings, other than the impact of a lower effective tax rate.

Maritime Link

On December 8, 2017, the first successful trial of the Maritime Link was achieved. The Maritime Link completed commissioning and entered service on January 15, 2018, enabling the transmission of electricity between Newfoundland and Labrador and Nova Scotia.

On September 11, 2017, the UARB approved NSPI's interim assessment payment to NSPML of the costs associated with the Maritime Link commencing when it is in service. The approved annual interim assessment payments are $110 million in 2018 and $111 million in 2019. In response to the delayed timing of energy delivery from the Muskrat Falls project, the approved interim assessment reflects NSPML's proposal to reduce the assessment by deferring the portion related to depreciation and amortization expense. Refer to the "Business Overview and Outlook", "NSPI" section for further details.

Increase in Common Dividend

On September 29, 2017, Emera's Board of Directors approved an increase in the annual common share dividend rate from $2.09 to $2.26. The first payment at the increased rate was effective November 15, 2017.

Hurricanes Irma and Maria

During the third quarter of 2017, operations in Florida and the Caribbean were impacted by Hurricanes Irma and Maria. Irma, a Category 5 hurricane at its height, impacted the Caribbean and Florida over the course of several days in September making landfall in Florida on September 10, 2017. Hurricane Maria made landfall in Dominica on September 19, 2017, as a Category 5 hurricane. There were no material impacts from these storms on St. Lucia, Grand Bahamas or Barbados.

TEC – As a result of Hurricane Irma, 57 per cent of Tampa Electric customers lost power. Power was restored to substantially all customers within seven days. There was minimal impact to earnings as a result of this storm. TEC incurred an estimated $105 million USD of storm restoration costs in 2017, of which $93 million USD are expected to be recoverable from the storm reserve, $8 million USD was charged to capital expenditures and $4 million USD to OM&G expenses. Tampa Electric petitioned the FPSC on December 28, 2017 for recovery of estimated storm costs in excess of the reserve for several named storms, including Hurricane Irma, and to replenish the balance in the reserve to the $56 million USD level that existed as of October 31, 2013. An amended petition was filed with the FPSC on January 30, 2018. Refer to the "Business Overview and Outlook", "Emera Florida and New Mexico" section for further details.

On January 30, 2018, Tampa Electric filed with the FPSC a settlement agreement which, if approved, will allow Tampa Electric to net the estimated amount of storm cost recovery against the utility's estimated 2018 tax reform benefits. Any difference would be trued up and recovered from or returned to customers in 2019. Beginning in January 2019 Tampa Electric would reflect the full impact of tax reform on Tampa Electric's base rates, provided that the FPSC's determinations have been finalized. A decision is expected in March 2018.

Domlec – Emera owns a controlling 51.9 per cent interest in Domlec, an integrated utility on the island of Dominica. The 48.1 per cent non-controlling interest is held by Dominica Social Security, the national pension scheme controlled by the Government, and other local investors. Emera's total investment in Domlec is $7 million USD. On September 19, 2017, Dominica experienced unprecedented damage as a result of Hurricane Maria, facing sustained winds of over 175 miles per hour. All 36,000 of Domlec's customers lost power following the storm.

The Company has implemented a restoration plan. All of Domlec's $13 million USD of long-term debt is held by The National Bank of Dominica and the bank has agreed to defer payment of principal and interest on this debt through to at least April 2018.

While Domlec's generating assets survived the storm with minimal damage, the Company's transmission and distribution assets were significantly impacted. Domlec maintains insurance for its generation fleet and, as with most utilities, transmission and distribution networks are self-insured. Management has completed its damage assessment and an estimated impairment provision has been recorded at December 31, 2017. Emera's portion of the estimated impairment provision is immaterial.

TEC Solar Investment and Solar Base Rate Adjustment ("SoBRA")

On September 28, 2017, Tampa Electric announced its intention to invest approximately $850 million USD over four years in 600 MW of new solar projects across its service territory. The first phase, which includes two projects totaling 150 MW, is scheduled to be completed in September 2018. The second phase, which includes four projects totaling 250 MW, is scheduled to be completed by January 1, 2019. Two other phases are scheduled to be completed by January 1 of 2020 and 2021.

A settlement agreement was filed with the FPSC requesting a base rate adjustment that provides for the recovery, upon in service, of up to 600 MW of investments in utility-scale solar projects. The settlement agreement also extends the general base rate freeze included in the 2013 Agreement to January 1, 2022, limits fuel hedging and investments in natural gas reserves and includes certain customer protections related to potential changes in federal tax policy. On November 6, 2017, the FPSC approved the settlement agreement. On December 12, 2017, Tampa Electric filed its petition along with supporting tariffs demonstrating the cost-effectiveness of the September 1, 2018 SoBRA representing 145 MW and $26 million in estimated revenue requirements. A decision by the FPSC to approve the tariffs on the first SoBRA filing is anticipated in the spring of 2018.

Appointments

Board of Directors
Effective November 10, 2017, Kent M. Harvey joined the Emera Board of Directors. Mr. Harvey is the former Chief Financial Officer for PG&E Corporation, a Fortune 200 regulated electric and gas utility.

Executive
Effective March 31, 2018 Rick Janega will be appointed the Chief Operating Officer, Electric Utilities – Canada, US Northeast and Caribbean. In addition to this new role, Mr. Janega will continue as President and Chief Executive Officer for Emera Newfoundland & Labrador.

Effective March 29, 2018, Chris Huskilson will retire as President and Chief Executive Officer ("CEO") and as a Director. Emera's Board of Directors has appointed Scott Balfour, current Chief Operating Officer and former Chief Financial Officer, as President and CEO upon Mr. Huskilson's retirement, and he will join the Board of Directors effective that date.

Effective December 1, 2017, Nancy Tower was appointed President and Chief Executive Officer of Tampa Electric. Gordon Gillette, Tampa Electric's previous President and Chief Executive Officer, retired on November 30, 2017. Ms. Tower was most recently the Chief Corporate Development Officer for Emera.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars
Balance, December 31, 2015	147.21	$ 2,157
Conversion of Convertible Debentures	51.99	2,115
Issuance of common stock	7.69	338
Issued for cash under Purchase Plans at market rate	2.51	115
Discount on shares purchased under Dividend Reinvestment Plan	-	(5)
Options exercised under senior management stock option plan	0.62	17
Employee Share Purchase Plan	-	1
Balance, December 31, 2016	210.02	$ 4,738
Conversion of Convertible Debentures (1)	0.15	6
Issuance of common stock (2)	14.61	680
Issued for cash 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**

(1) As at December 31, 2017, a total of 52.14 million common shares of the Company were issued, representing conversion into common shares of more than 99.9% of the Convertible Debentures.
(2) On December 28, 2017, Emera completed an offering of 14.6 million common shares, at $47.90 per common share, for gross proceeds of approximately $700 million. The net proceeds were $680 million after $20 million of issuance costs, net of taxes.

As at January 29, 2018, the amount of issued and outstanding common shares was 229.3 million.

The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended December 31, 2017 was 215.3 million (2016 – 204.1 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2017 was 213.4 million (2016 – 171.4 million).

EMERA FLORIDA AND NEW MEXICO

Financial Highlights

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016*
Operating revenues – regulated electric	$ **470**	$ 454	$ **2,048**	$ 1,039
Operating revenues – regulated gas	**206**	202	**732**	349
Operating revenues – non-regulated	**4**	4	**13**	7
Total operating revenues	**680**	660	**2,793**	1,395
Regulated fuel for generation and purchased power	**143**	159	**634**	371
Regulated cost of natural gas	**84**	80	**292**	133
Adjusted contribution to consolidated net income – USD	$ **63**	$ 47	$ **295**	$ 131
Adjusted contribution to consolidated net income – CAD	$ **80**	$ 63	$ **382**	$ 172
Revaluation of US non-regulated deferred income taxes	$ **(221)**	$ -	$ **(221)**	$ -
Contribution to consolidated net income – USD	$ **(158)**	$ 47	$ **74**	$ 131
Contribution to consolidated net income – CAD	$ **(203)**	$ 63	$ **99**	$ 172
Adjusted contribution to consolidated earnings per common share – CAD	$ **0.37**	$ 0.31	$ **1.79**	$ 1.00
Contribution to consolidated earnings per common share – CAD	$ **(0.94)**	$ 0.31	$ **0.46**	$ 1.00
Net income weighted average foreign exchange rate – CAD/USD	$ **1.28**	$ 1.34	$ **1.34**	$ 1.31
EBITDA – USD	$ **252**	$ 209	$ **1,060**	$ 477
EBITDA – CAD	$ **320**	$ 279	$ **1,374**	$ 629

*2016 Financial results of Emera Florida and New Mexico are from July 1, 2016.

Revaluation of US non-regulated deferred income taxes

Due to the enactment of US Tax Cuts and Jobs Act of 2017, Emera Florida and New Mexico recorded a non-cash income tax expense resulting from the provisional revaluation of the existing US non-regulated net deferred income tax assets. This provisional revaluation of an existing asset is not the result of any operational or market driven event and therefore management believes excluding from adjusted net income the effect of this provisional revaluation 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 millions of US dollars		Three months ended December 31
Contribution to consolidated net income – 2016	**$**	**47**
Increased operating revenues - see Operating Revenues - Regulated Electric below		16
Increased operating revenues - see Operating Revenues - Regulated Gas below		4
Decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below		16
Increased cost of natural gas sold - see Regulated Cost of Natural Gas below		(4)
Decreased OM&G expenses, primarily due to fewer planned outages and generation maintenance and timing of transmission and distribution line clearance, inspections and other maintenance activity		20
Increased depreciation and amortization due to increased property, plant and equipment; partially offset by decreases in depreciation rates related to PGS's FPSC approved depreciation study		(6)
Decreased AFUDC due to Polk Power Station expansion going into service in January 2017		(9)
Increased income tax expense, primarily due to increased income before provision for income taxes		(18)
Revaluation of US non-regulated deferred income taxes due to tax reform		(221)
Other		(3)
Contribution to consolidated net income – 2017	**$**	**(158)**

Emera Florida and New Mexico's CAD adjusted contribution to consolidated net income increased $17 million to $80 million in Q4 2017 from $63 million during the same period in 2016. The impact of the change in the foreign exchange rate decreased CAD adjusted earnings by $4 million compared to Q4 2016.

Emera Florida and New Mexico's adjusted contribution is summarized in the following table:

For the millions of US dollars		Three months ended December 31				Twelve months ended December 31		
		2017		2016		**2017**		2016*
Tampa Electric	**$**	**57**	$	**38**	**$**	**274**	$	**126**
PGS		**12**		**9**		**43**		**15**
NMGC		**10**		**10**		**22**		**9**
Other (1)		**(16)**		**(10)**		**(44)**		**(19)**
Adjusted contribution to consolidated net income	**$**	**63**	$	**47**	**$**	**295**	$	**131**

(1) Other includes TECO Finance and administration costs.

*Financial results of Emera Florida and New Mexico are from July 1, 2016.

Emera's 2016 results reflect six months of Emera Florida and New Mexico operations as the acquisition was completed on July 1, 2016. Prior year data discussed below reflects the full year of operation for comparison purposes only.

Tampa Electric's 2017 adjusted net income increased $29 million to $274 million compared to $245 million in 2016 due primarily to higher base revenues related to the completion of the Polk Power Station expansion project and lower OM&G partially offset by increased depreciation and property tax expense, and lower AFUDC earnings. Unfavourable winter weather impacts on base revenues were offset by warmer spring weather and customer growth. OM&G was lower in 2017 due to decreased generation outages and other maintenance costs, and higher administrative overhead allocated to capital due to higher capital spending.

In September 2017, Tampa Electric was impacted by Hurricane Irma. The majority of Hurricane Irma restoration costs will be charged against Tampa Electric's FPSC approved storm reserve resulting in minimal impact on earnings. Estimated total restoration costs are $105 million, with $93 million charged to the storm reserve, $8 million charged to capital expenditures and $4 million charged to OM&G. Tampa Electric petitioned the FPSC on December 28, 2017 for recovery of estimated storm costs in excess of the reserve for several named storms, including Hurricane Irma. An amended petition was filed with the FPSC on January 30, 2018.

On January 30, 2018, Tampa Electric filed with the FPSC a settlement agreement which, if approved, will allow Tampa Electric to net the estimated amount of storm cost recovery against the utility's estimated 2018 tax reform benefits. Any difference would be trued up and recovered from or returned to customers in 2019. Beginning in January 2019 Tampa Electric would reflect the full impact of tax reform on Tampa Electric's base rates, provided that the FPSC's determinations have been finalized. A decision is expected in March 2018.

On June 29, 2017, a tragic accident occurred during work being conducted at Tampa Electric's Big Bend Power Station Unit Two, resulting in employee and contractor fatalities. The financial impact to Tampa Electric is expected to be substantially covered by insurance.

PGS's 2017 net income increased $8 million to $43 million compared to $35 million in 2016 primarily due to lower depreciation expense, slightly higher base revenue and an increase in return on investments related to the FPSC approved Cast Iron/Bare Steel Pipe Replacement clause. Base revenue was slightly higher as impacts from customer growth and the strong Florida economy were offset by unfavourable winter weather impacts earlier this year.

NMGC's 2017 adjusted net income decreased $2 million to $22 million compared to $24 million in 2016.

2017 other adjusted net loss increased $8 million to $44 million compared to $36 million in 2016, primarily due to executive retirement compensation expense in 2017.

Electric and Gas Revenues

Electric and gas sales volumes are primarily driven by general economic conditions, population and weather. Residential and commercial electricity and gas sales are seasonal. In Florida, Q3 is the strongest period for electricity sales, reflecting warmer weather and cooling demand. In New Mexico and Florida, Q1 is the strongest period for gas sales due to colder weather and heating demand.

Emera Florida and New Mexico's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. The gas utilities' industrial customers include manufacturing facilities and other large volume operations. Other sales volumes consist primarily of off-system sales to other utilities and revenues from street lighting.

Operating Revenues – Regulated Electric

Electric revenues increased $16 million to $470 million in Q4 2017 compared to $454 million in Q4 2016, primarily due to $28 million of higher base revenues related to completion of the Polk Power Station expansion in January 2017. This increase was offset by lower clause-related revenues due to return of prior year fuel over-recoveries through current rates and higher sales volume due to customer growth. For the year ended December 31, 2017, electric revenues increased $87 million to $2,048 million compared to $1,961 million in 2016, primarily due to $112 million of higher base revenues related to the Polk Power Station expansion partially offset by lower sales volumes due to mild winter weather in the Q1 and lower clause-related revenues.

Electric revenues are summarized in the following by customer class:

Q4 Electric Revenues
millions of US dollars

		2017		2016
Residential	**$**	**237**	$	235
Commercial		**139**		146
Industrial		**39**		40
Other (1)		**55**		33
Total	**$**	**470**	$	454

(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

		2017		2016*
Residential	**$**	**1,006**	$	566
Commercial		**578**		313
Industrial		**158**		82
Other (1)		**306**		78
	$	**2,048**	$	1,039

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

*Financial results of Emera Florida and New Mexico are from July 1, 2016.

Q4 Electric Sales Volumes
GWh

	2017	2016
Residential	2,113	2,072
Commercial	1,503	1,543
Industrial	495	491
Other	489	457
Total	4,600	4,563

Annual Electric Sales Volumes
GWh

	2017	**2016***
Residential	**9,029**	9,188
Commercial	**6,362**	6,310
Industrial	**2,025**	1,929
Other	**1,771**	1,808
Total	**19,187**	19,235

*2016 data is for comparative purposes only. TECO Energy was acquired on July 1, 2016.

Operating Revenues – Regulated Gas

Gas revenues increased $4 million to $206 million in Q4 2017 compared to $202 million in Q4 2016, primarily due to the pass through of higher commodity costs and customer growth in Florida partially offset by lower NMGC sales volumes due to milder weather in Q4 2017. For the year ended December 31, 2017, gas revenues increased $7 million to $732 million compared to $725 million in 2016, primarily due to higher commodity costs and customer growth in Florida, partially offset by lower sales volumes due to unfavourable winter weather in Q1 2017 in both Florida and New Mexico in addition to the Q4 2017 weather impacts at NMGC.

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

Q4 Gas Revenues
millions of US dollars

		2017		2016
Residential	**$**	**110**	$	**107**
Commercial		**60**		**59**
Industrial		**9**		**12**
Other (1)		**27**		**24**
Total	**$**	**206**	$	**202**

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

Annual Gas Revenues
millions of US dollars

		2017		2016*
Residential	**$**	**367**	$	**163**
Commercial		**220**		**101**
Industrial		**35**		**21**
Other (1)		**110**		**64**
Total	**$**	**732**	$	**349**

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

* Financial results of Emera Florida and New Mexico are from July 1, 2016.

Q4 Gas Sales Volumes

Therms (millions)

	2017	2016
Residential	**113**	116
Commercial	**202**	204
Industrial	**292**	289
Other	**53**	56
Total	**660**	665

Annual Gas Sales Volumes

Therms (millions)

	2017	2016*
Residential	**344**	365
Commercial	**754**	766
Industrial	**1,216**	1,236
Other	**245**	299
Total	**2,559**	2,666

*2016 data is for comparative purposes only. TECO Energy was acquired on July 1, 2016.

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 5,218 MW, which is supplemented by 371 MW contracted with other regulated utilities and independent power producers in Florida. 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.

Tampa Electric's 460 MW Polk Power Station expansion project and 19 MW Big Bend Solar array went into commercial operation in January and February of 2017, respectively.

Q4 Production Volumes

GWh

	2017	2016
Natural gas (1)	**3,365**	1,958
Coal (1)(2)	**905**	1,872
Oil and petcoke	**228**	220
Solar	**9**	1
Purchased power (1)	**171**	492
Total production volumes	**4,678**	4,543

(1) Natural gas production was higher and purchased power was lower due to completion of Polk Power Station expansion in January 2017 and expiration of a purchased power contract in December 2016.

(2) Lower coal production and higher natural gas production due to running Big Bend Power Station units 1-2 on natural gas.

Annual Production

GWh

	2017	2016*
Natural gas (1)	**13,685**	9,870
Coal (1)(2)	**5,089**	6,767
Oil and petcoke	**924**	972
Solar	**45**	3
Purchased power (1)	**559**	2,556
Total production volumes	**20,302**	20,168

(1) Natural gas production was higher and purchased power was lower due to completion of Polk Power Station expansion in January 2017 and expiration of a purchased power contract in December 2016.

(2) Lower coal production and higher natural gas production due to Big Bend Power Station outages and running units 1-2 on natural gas.

*2016 data is for comparative purposes only. TECO Energy was acquired on July 1, 2016.

Q4 Average Fuel

US dollars	2017	2016
Dollars per MWh	$ 31	$ 35

Annual Average Fuel

US dollars	2017	2016*
Dollars per MWh	$ 31	$ 33

*2016 data is for comparison purposes only. TECO Energy was acquired on July 1, 2016.

Q4 and annual average fuel cost per MWh was lower in 2017 than 2016 primarily due to lower purchased power and more natural gas production as a result of the new Polk Power Station expansion.

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 (after renewable energy from solar arrays), 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 fuel for generation and purchased power decreased $16 million to $143 million in Q4 2017 compared to $159 million in Q4 2016. For the year ended December 31, 2017, it decreased $31 million to $634 million compared to $665 million for the same period in 2016. These decreases were primarily due to lower purchased power costs in 2017. In 2016, Tampa Electric was purchasing more power to cover outages related to the Polk Power Station expansion project.

Cost of Natural Gas

Emera Florida and New Mexico's gas utilities, 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 service territory is situated between two large natural gas production basins (the San Juan Basin in northwest New Mexico and the Permian Basin in southeastern New Mexico). Natural gas is transported from these production basins on major interstate pipelines and NMGC's intrastate transmission system to customers using NMGC's distribution system.

In Florida, natural gas service is unbundled for non-residential customers and residential customers that use more than 1,999 therms annually that elect this option, affording these customers the opportunity to purchase gas from any provider. In New Mexico, NMGC is required to provide transportation-only services for all customer classes if requested. The net result of unbundling is a shift from bundled transportation and commodity sales to transportation-only sales. 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 $4 million to $84 million in Q4 2017 compared to $80 million in Q4 2016 primarily due to higher commodity costs. For the year ended December 31, 2017, regulated cost of natural gas increased $11 million to $292 million in 2017 compared to $281 million in 2017 primarily due to higher commodity costs partially offset by lower sales volumes due to unfavourable winter weather in Q1 2017.

Gas sales by type are summarized in the following tables:

Q4 Gas Sales Volumes by Type

Therms (millions)	**2017**	2016
System Supply	**194**	198
Transportation	**466**	467
Total	**660**	665

Annual Gas Sales Volumes by Type

Therms (millions)	**2017**	**2016***
System Supply	**671**	744
Transportation	**1,888**	1,922
Total	**2,559**	2,666

*2016 data is for comparative purposes only. TECO Energy was acquired on July 1, 2016.

Gas sales volumes in Q4 2017 were lower than Q4 2016, primarily due to warmer weather in New Mexico partially offset by customer growth in Florida. For the year ended December 31, 2017, gas sales volumes decreased compared to in 2016, primarily due to unfavourable winter weather in Q1 2017 in both Florida and New Mexico.

Regulatory Recovery Mechanisms

Tampa Electric

Fuel Recovery Clause
Tampa Electric has a fuel recovery clause that is 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. In October 2017, the FPSC approved the 2018 cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs.

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 the 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. In 2012, the FPSC approved a new 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 of approximately 5 per cent, or 800 kilometres, of the PGS system at a cost of approximately $80 million 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. The NMPRC requires that NMGC annually file a reconciliation of the PGAC period costs and recoveries. NMGC's annual PGAC period runs from September 1 to August 31 and the reconciliation is filed in December. 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

Financial Highlights

For the millions of Canadian dollars (except per share amounts)		Three months ended December 31		Year ended December 31	
		2017	2016	**2017**	2016
Operating revenues – regulated electric	**$**	**355**	$ 352	**$ 1,338**	$ 1,356
Regulated fuel for generation and purchased power (1)		**141**	136	**477**	490
Contribution to consolidated net income	**$**	**23**	$ 34	**$ 129**	$ 130
Contribution to consolidated earnings per common share - basic	**$**	**0.11**	$ 0.17	**$ 0.60**	$ 0.76
EBITDA	**$**	**104**	$ 116	**$ 466**	$ 463

(1) Regulated fuel for generation and purchased power includes the Fuel Adjustment Mechanism on the Consolidated Income Statement, however it is excluded in the segment overview.

Net Income

Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2016	**$ 34**	**$ 130**
Increased (decreased) operating revenues - see Operating Revenues - Regulated Electric below	3	(18)
(Increased) decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	(5)	13
Increased OM&G expenses quarter-over-quarter, primarily due to higher costs for vegetation management and information technology partially offset by lower storm costs. Year-over-year decrease, primarily due to higher administrative overheads allocated to capital due to higher capital spending, decreased storm costs, lower pension expense and lower maintenance costs partially offset by increased costs for information technology and vegetation management	(6)	7
Increased depreciation and amortization due to increased property, plant and equipment	(3)	(10)
Increased interest expense, net, primarily due to higher interest expense on the FAM regulatory liability and decreased interest income on the demand side management ("DSM") regulatory asset which is no longer financed by NSPI	(2)	(6)
Decreased income tax expense, primarily due to increased tax deductions in excess of accounting depreciation related to property, plant and equipment and decreased income before provision for income taxes	6	12
Other	(4)	1
Contribution to consolidated net income – 2017	**$ 23**	**$ 129**

NSPI's contribution to consolidated net income decreased $11 million to $23 million in Q4 2017 compared to $34 million in Q4 2016. For the year ended December 31, 2017, NSPI's contribution to consolidated net income was consistent with 2016.

Operating Revenues – Regulated Electric

Operating revenues increased $3 million to $355 million in Q4 2017 compared to $352 million in Q4 2016. Revenues increased as a result of an increase in fuel related electricity pricing in 2017 and an increase in sales volumes due to load growth. This was partially offset by a decrease in sales volume due to weather and due to the Maritime Link interim assessment decision.

For the year ended December 31, 2017, operating revenues decreased $18 million to $1,338 million compared to $1,356 million in 2016. Revenues decreased due to the one-time refund in 2017 of $36 million of prior year fuel related revenues and by $16 million due to the Maritime Link interim assessment decision. This was partially offset by a $24 million increase as a result of fuel related electricity pricing effective January 1, 2017 and an $8 million increase in sales volumes due to load growth.

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

Q4 Electric Revenues
millions of Canadian dollars

	2017	2016
Residential	**$ 178**	$ 181
Commercial	**101**	101
Industrial	**56**	51
Other	**13**	10
Total	**$ 348**	$ 343

Annual Electric Revenues
millions of Canadian dollars

	2017	2016
Residential	**$ 679**	$ 689
Commercial	**387**	399
Industrial	**200**	197
Other	**43**	42
Total	**$ 1,309**	$ 1,327

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

Q4 Electric Sales Volumes
GWh

	2017	2016
Residential	**1,120**	1,143
Commercial	**771**	764
Industrial	**637**	632
Other	**85**	80
Total	**2,613**	2,619

Annual Electric Sales Volumes
GWh

	2017	2016
Residential	**4,374**	4,318
Commercial	**3,060**	3,062
Industrial	**2,466**	2,445
Other	**345**	293
Total	**10,245**	10,118

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $5 million to $141 million in Q4 2017 compared to $136 million in Q4 2016 due to changes in generation mix and plant performance, and decreased NSPI owned hydro and wind production, partially offset by decreased commodity prices. For the year ended December 31, 2017, regulated fuel for generation and purchased fuel power decreased $13 million to $477 million compared to $490 million in 2016 due to decreased commodity prices, partially offset by increased sales volumes.

NSPI's FAM regulatory liability balance increased $83 million from $94 million at December 31, 2016 to $177 million at December 31, 2017 as a result of an over-recovery of current period fuel costs, including recovery of Maritime Link revenues that are to be refunded to customers as a result of the interim assessment decision, excess non-fuel revenues, interest on the FAM balance and the benefit of tax treatment on South Canoe and Sable wind farms. These were partially reduced by the refund to customers of prior years' fuel costs.

Q4 Production Volumes
GWh

	2017	2016
Coal	**1,168**	1,380
Natural gas	**349**	281
Oil and petcoke	**352**	391
Purchased power – other	**220**	129
Total non-renewables	**2,089**	2,181
Wind and hydro – renewables	**190**	230
Purchased power – IPP	**374**	314
Purchased power – COMFIT	**158**	110
Biomass – renewables	**53**	52
Total renewables	**775**	706
Total production volumes	**2,864**	2,887

Annual Production Volumes
GWh

	2017	2016
Coal	**4,839**	4,810
Natural gas	**1,444**	1,244
Oil and petcoke	**1,169**	1,499
Purchased power – other	**481**	430
Total non-renewables	**7,933**	7,983
Wind and hydro – renewables	**1,121**	1,081
Purchased power – IPP	**1,246**	1,147
Purchased power – COMFIT	**525**	414
Biomass – renewables	**153**	214
Total renewables	**3,045**	2,856
Total production volumes	**10,978**	10,839

Q4 Average Fuel Costs

	2017	2016
Dollars per MWh produced	**$ 49**	$ 47

Annual Average Fuel Costs

	2017	2016
Dollars per MWh produced	**$ 43**	$ 45

Average unit fuel costs in Q4 2017 increased compared to Q4 2016 primarily due to unfavourable generation mix and decreased NSPI-owned hydro and wind generation, partially offset by favourable commodity pricing. Year-over-year, average unit fuel costs decreased in 2017 compared to 2016, primarily due to favourable solid fuel pricing, partially offset by unfavourable generation mix.

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 power purchase agreements 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. However, declines in natural gas prices and better overall thermal efficiencies have at times resulted in natural gas dispatching before petcoke and coal units. Oil, biomass and purchased power have the next lowest fuel cost, depending on the relative pricing of each.

The generation mix is transforming with the addition of new non-dispatchable renewable energy sources such as wind, 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

Financial Highlights

All amounts are reported in USD, unless otherwise stated.

For the millions of USD (except per share amounts)	Three months ended December 31		For the year ended December 31	
	2017	2016	**2017**	2016
Operating revenues – regulated electric	**$ 55**	$ 55	**$ 228**	$ 223
Regulated fuel for generation and purchased power [1]	**17**	12	**64**	54
Contribution to consolidated net income – USD	**$ 7**	$ 9	**$ 36**	$ 36
Contribution to consolidated net income – CAD	**$ 8**	$ 11	**$ 46**	$ 47
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.04**	$ 0.05	**$ 0.22**	$ 0.27
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.27**	$ 1.34	**$ 1.30**	$ 1.32
EBITDA – USD	**$ 23**	$ 28	**$ 107**	$ 107
EBITDA – CAD	**$ 29**	$ 37	**$ 139**	$ 141

(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 millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2016	**$ 9**	**$ 36**
Increased operating revenues – see Operating Revenues – Regulated Electric section below	-	5
Increased regulated fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power section below	(5)	(10)
Decreased OM&G year-over-year, primarily due to storm expenses incurred and losses recognized on disallowed and abandoned plant in 2016 partially offset by reduced capitalized construction overheads in 2017	(1)	3
Decreased depreciation and amortization due to lower regulatory amortization related to changes in stranded costs and purchased power	3	3
Increased income tax expense primarily due to decreased excess deferred income tax amortization and increased income before provision for income taxes	-	(3)
Other	1	2
Contribution to consolidated net income – 2017	**$ 7**	**$ 36**

Emera Maine's CAD contribution to consolidated net income decreased by $3 million to $8 million in Q4 2017 from $11 million in Q4 2016. For the year ended December 31, 2017, Emera Maine's CAD contribution to consolidated net income decreased $1 million to $46 million, from $47 million in 2016. The foreign exchange rate had minimal impact for the three months and year ended December 31, 2017.

Operating Revenues – Regulated Electric

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

		2017	2016
Electric revenues	**$**	**41**	$ 40
Transmission pool revenues		**10**	12
Resale of purchased power		**4**	3
Operating revenues – regulated electric	**$**	**55**	$ 55

Annual Operating Revenues – Regulated Electric
millions of US dollars

		2017	2016
Electric revenues	**$**	**169**	$ 160
Transmission pool revenues		**48**	51
Resale of purchased power		**11**	12
Operating revenues – regulated electric	**$**	**228**	$ 223

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

Q4 Electric Revenues
millions of US dollars

		2017	2016
Residential	**$**	**21**	$ 20
Commercial		**16**	15
Industrial		**2**	3
Other (1)		**2**	2
Total	**$**	**41**	$ 40

Annual Electric Revenues
millions of US dollars

		2017	2016
Residential	**$**	**81**	$ 77
Commercial		**62**	60
Industrial		**12**	13
Other (1)		**14**	10
Total	**$**	**169**	$ 160

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

Electric revenues increased $1 million to $41 million in Q4 2017 compared to $40 million in Q4 2016. For the year ended December 31, 2017, electric revenues increased $9 million to $169 million in 2017 compared to $160 million in 2016 due to transmission and distribution rate changes.

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

Q4 Electric Sales Volumes
GWh

	2017	2016
Residential	**207**	202
Commercial	**194**	192
Industrial	**87**	85
Other	**3**	2
Total	**491**	481

Annual Electric Sales Volumes
GWh

	2017	2016
Residential	**802**	790
Commercial	**773**	776
Industrial	**349**	352
Other	**14**	13
Total	**1,938**	1,931

Regulated Fuel for Generation and Purchased Power

Emera Maine’s regulated fuel for generation and purchased power increased $5 million to $17 million in Q4 2017 compared to $12 million in Q4 2016. For the year ended December 31, 2017, regulated fuel for generation and purchased power increased $10 million to $64 million compared to $54 million in 2016. The increases were due to increased volumes and changes in market prices associated with long term purchase power contracts. The power purchased under these arrangements is resold at market rates significantly below the contract rates. The difference between the cost of power purchased under these arrangements and the revenue collected is recovered through stranded costs rates under a full reconciliation rate mechanism.

Revaluation of US regulated deferred income taxes

Due to the enactment of US Tax Cuts and Jobs Act of 2017 Emera Maine recorded a non-cash provisional revaluation of the existing US regulated net deferred income tax liabilities. Emera Maine has 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 has an impact on the 2017 balance sheet but no impact on 2017 earnings.

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. The 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. 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. 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 CARIBBEAN

Financial Highlights

All amounts are reported in USD, unless otherwise stated.

For the millions of USD (except per share amounts)	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
Operating revenues – regulated electric	**$ 84**	$ 78	**$ 334**	$ 316
Regulated fuel for generation and purchased power	**41**	36	**152**	130
Contribution to consolidated net income – USD	**$ 1**	$ 6	**$ 24**	$ 77
Contribution to consolidated net income – CAD	**$ 1**	$ 8	**$ 31**	$ 100
Contribution to consolidated earnings per common share – CAD	**$ -**	$ 0.04	**$ 0.15**	$ 0.58
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.25**	$ 1.34	**$ 1.30**	$ 1.31
EBITDA – USD	**$ 11**	$ 19	**$ 87**	$ 144
EBITDA – CAD	**$ 14**	$ 25	**$ 113**	$ 189

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2016	**$ 6**	**$ 77**
Increased operating revenues - see Operating Revenues - Regulated Electric below	6	18
Increased regulated fuel for generation - see Regulated Fuel for Generation and Purchased Power below	(5)	(22)
Decreased other income quarter-over-quarter mainly due to the pre-tax impairment charge as a result of damage to Domlec's assets from Hurricane Maria. Year-over-year decrease mainly due to a pre-tax gain recognized on the BLPC SIF regulatory liability in 2016	(4)	(48)
Increased interest expense reflecting interest charges on debt issued in Q4 2016 at ECI	(2)	(8)
Decreased income tax expense, primarily due to decreased income before provision for income taxes. Year-over-year decrease also due to a pre-tax gain recognized on the BLPC SIF regulatory liability in 2016	3	10
Other	(3)	(3)
Contribution to consolidated net income – 2017	**$ 1**	**$ 24**

Emera Caribbean’s CAD contribution to consolidated net income decreased by $7 million to $1 million in Q4 2017 compared to $8 million in Q4 2016. For the year ended December 31, 2017, Emera Caribbean’s CAD contribution to consolidated net income decreased by $69 million to $31 million in 2017 compared to $100 million in 2016. The foreign exchange rate had minimal impact for the three months and year ended December 31, 2017.

Operating Revenues – Regulated Electric

Operating revenues increased $6 million to $84 million in Q4 2017 compared to $78 million in Q4 2016. This increase reflected an increase in fuel charge as a result of higher fuel prices in 2017 at BLPC, higher sales volumes at GBPC due to the partial recovery of the temporary decrease of load as a result of Hurricane Matthew lowering volumes in 2016, partially offset by lower sales volumes at Domlec due to the impact of Hurricane Maria.

For the year ended December 31, 2017, operating revenues increased $18 million to $334 million compared to $316 million in 2016 due to an increase in fuel charge as a result of higher fuel prices in 2017 at BLPC, partially offset by lower sales volumes at Domlec due to the impact of Hurricane Maria.

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

Q4 Electric Revenues
millions of US dollars

	2017	2016
Residential	**$ 27**	$ 26
Commercial	**49**	46
Industrial	**6**	5
Other	**2**	1
Total	**$ 84**	$ 78

Annual Electric Revenues
millions of US dollars

	2017	2016
Residential	$ **110**	$ 104
Commercial	**191**	179
Industrial	**23**	24
Other	**7**	6
Total	$ **331**	$ 313

Q4 Electric Sales Volumes
GWh

	2017	2016
Residential	**105**	110
Commercial	**182**	185
Industrial	**20**	17
Other	**4**	3
Total	**311**	315

Annual Electric Sales Volumes
GWh

	2017	2016
Residential	**462**	465
Commercial	**753**	766
Industrial	**85**	89
Other	**17**	19
Total	**1,317**	1,339

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $5 million to $41 million in Q4 2017 compared to $36 million in Q4 2016 and year-to-date and increased $22 million to $152 million compared to $130 million during the same period in 2016, primarily due to higher oil prices.

Q4 Production Volumes
GWh

	2017	2016
Oil	335	337
Hydro	5	9
Solar	1	4
Total	**341**	350

Annual Production Volumes
GWh

	2017	2016
Oil	**1,386**	1,417
Hydro	**30**	36
Solar	**14**	9
Total	**1,430**	1,462

Q4 Average Fuel

	2017	2016
Dollars per MWh	**$ 120**	$ 103

Annual Average Fuel

	2017	2016
Dollars per MWh	**$ 106**	$ 89

The change in the average fuel costs for the quarter and year was the result of 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 prudent fuel costs from customers in a timely manner. The Barbados Fair Trading Commission 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 prudent fuel costs from customers in a timely manner. In December 2016, the GBPA approved holding the all-in (fuel and base) rates consistent with 2016 levels for five years (2017-2021).

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.

As a result of Hurricane Matthew in 2016, a regulatory asset was established to recover associated restoration costs. In addition, 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.

Domlec

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

EMERA ENERGY

Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
Marketing and trading margin (1) (2)	**$ 24**	$ 23	**$ 44**	$ 58
Electricity sales (3)	**115**	109	**345**	460
Total operating revenues – non-regulated	**139**	132	**389**	518
Non-regulated fuel for generation and purchased power (4)	**65**	84	**214**	334
Adjusted contribution to consolidated net income	**$ 26**	$ 5	**$ 24**	$ 24
Revaluation of US non-regulated deferred income taxes	**$ 12**	$ -	**$ 12**	$ -
After-tax derivative mark-to-market gain (loss)	**$ (48)**	$ (36)	**$ 57**	$ (134)
Contribution to consolidated net income	**$ (10)**	$ (31)	**$ 93**	$ (110)
Adjusted contribution to consolidated earnings per common share – basic	**$ 0.12**	$ 0.02	**$ 0.11**	$ 0.14
Contribution to consolidated earnings per common share – basic	**$ (0.05)**	$ (0.15)	**$ 0.44**	$ (0.64)
Adjusted EBITDA	**$ 61**	$ 25	**$ 107**	$ 99

(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 loss of $37 million in Q4 2017 (2016 - $64 million loss) and a gain of $119 million for the year ended December 31, 2017 (2016 - $203 million loss).
(3) Electricity sales exclude a pre-tax mark-to-market loss of $40 million in Q4 2017 (2016 - nil) and a loss of $43 million for the year ended December 31, 2017 (2016 - $7 million loss).
(4) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market gain of $3 million in Q4 2017 (2016 – $13 million gain) and a loss of $1 million for the year ended December 31, 2017 (2016 - $18 million gain).

Revaluation of US non-regulated deferred income taxes

Due to the enactment of US Tax Cuts and Jobs Act of 2017, Emera Energy recorded a non-cash income tax recovery resulting from the provisional revaluation of the existing US non-regulated net deferred income tax liabilities. This provisional revaluation of an existing liability is not the result of any operational or market driven event and therefore management believes excluding from adjusted net income the effect of this provisional revaluation 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 sales", "Non-regulated fuel for generation and purchased power", "Income from equity investments" and "Income tax expense (recovery)" are affected by mark-to-market ("MTM") adjustments. 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 YTD 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.

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2016	**$ (31)**	**$ (110)**
Increased marketing and trading margin quarter-over-quarter and decreased marketing and trading margin year-over-year - See Marketing and Trading Margin section below	1	(14)
Increased electricity sales quarter-over-quarter, primarily due to higher capacity revenue for NEGG, partially offset by decreased electricity sales at Bayside Power. Year-over-year decrease due to lower hedged power prices in Q1 2017 compared to Q1 2016, lower sales volumes as a result of an unplanned outage at the Bridgeport Facility in 2017 and less favourable market conditions in 2017, partially offset by the fourth quarter factors noted above	6	(115)
Decreased non-regulated fuel for generation and purchased power quarter-over-quarter, primarily due to decreased natural gas purchases at Bayside Power. Year-over-year also due to decreased sales volumes as a result of an unplanned outage at the Bridgeport Facility in 2017, lower hedged natural gas prices in Q1 2017 compared to Q1 2016, recognition of prior period state fuel taxes in Q2 2016 and less favourable market conditions in 2017	19	120
Increased income tax expense, primarily due to increased income before provision for income taxes	(12)	(1)
Decreased mark-to-market, net of tax quarter-over-quarter, primarily due to changes in existing positions. Year-over-year increase due to changes in existing positions on long-term natural gas contracts and the reversal of 2016 mark-to-market losses	(12)	191
Revaluation of US non-regulated deferred income taxes due to tax reform	12	12
Other	7	10
Contribution to consolidated net income – 2017	**$ (10)**	**$ 93**

A portion of earnings are exposed to foreign exchange fluctuations, thereby affecting adjusted CAD contribution to net earnings. The impact of the change in USD/CAD exchange rate quarter-over-quarter decreased the loss in CAD by $1 million in Q4 2017 compared to Q4 2016. Year-over-year the impact of the change in the foreign exchange rate decreased CAD adjusted earnings by $10 million in 2017 compared to 2016.

Energy Services

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 shale gas region. 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.

Adjusted EBITDA

Adjusted EBITDA for Emera Energy Services is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
Marketing and trading margin	**$ 24**	$ 23	**$ 44**	$ 58
OM&G	**5**	7	**19**	22
Other income (expenses), net	**1**	1	**-**	(3)
Adjusted EBITDA	**$ 20**	$ 17	**$ 25**	$ 33

Marketing and Trading Margin

Marketing and trading margin increased $1 million to $24 million in Q4 2017 compared to $23 million in Q4 2016. For the year ended December 31, 2017, marketing and trading margin decreased $14 million to $44 million compared to $58 million in 2016. This reflected weaker market conditions in 2017 compared to 2016, specifically the impact of weather in Q1 and Q3 and increased gas transportation infrastructure in the northeastern United States that resulted in fewer optimization opportunities. This was partially offset by lower short-term fixed cost commitments for transportation and growth in the volume of business in 2017.

Generation

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

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

Wholly Owned Generation Facilities	Location	Capacity (MW)	Commissioning/ In-Service Date	Fuel	Description
New England					
Bridgeport	Connecticut	560	1999	Natural gas	Selling electricity and capacity to ISO-NE
Tiverton (1)	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 power purchase agreement ("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**			

(1) In Q4 2016, an upgrade at Tiverton increased its nameplate capacity from 265 MW to 290 MW.

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 fuel prices and power demand. 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.

Emera Energy Generation

Adjusted EBITDA

Adjusted EBITDA is summarized in the following tables:

For the	Three months ended December 31					
millions of Canadian dollars	New England		Maritime Canada		Total	
	2017	2016	**2017**	2016	**2017**	2016
Energy sales	**$ 78**	$ 70	**$ 9**	$ 29	**$ 87**	$ 99
Capacity and other	**27**	10	**1**	-	**28**	10
Electricity sales	**$ 105**	$ 80	$ **10**	$ 29	**$ 115**	$ 109
Non-regulated fuel for generation and purchased power	**63**	61	**1**	22	**64**	83
Provincial, state and municipal taxes	**3**	3	**-**	1	**3**	4
OM&G	**11**	11	**4**	4	**15**	15
Other income (expenses), net	**1**	1	**-**	-	**1**	1
Adjusted EBITDA	**$ 29**	$ 6	**$ 5**	$ 2	**$ 34**	$ 8

For the millions of Canadian dollars	New England 2017	New England 2016	Maritime Canada 2017	Maritime Canada 2016	Total 2017	Total 2016
						Year ended December 31
Energy sales	**$ 210**	$ 327	**$ 53**	$ 86	**$ 263**	$ 413
Capacity and other	**79**	47	**3**	-	**82**	47
Electricity sales	**$ 289**	$ 374	**$ 56**	$ 86	**$ 345**	$ 460
Non-regulated fuel for generation and purchased power	**175**	261	**35**	65	**210**	326
Provincial, state and municipal taxes	**11**	8	**1**	1	**12**	9
OM&G	**39**	42	**19**	21	**58**	63
Other income (expenses), net	**1**	1	**-**	1	**1**	2
Adjusted EBITDA	**$ 65**	$ 64	**$ 1**	$ -	**$ 66**	$ 64

Adjusted EBITDA increased $26 million to $34 million in Q4 2017 from $8 million in Q4 2016 mainly due to higher capacity prices that came into effect for NEGG in June 2017, more favourable market conditions in Q4 2017 and fewer planned outage hours at Tiverton Power in Q4 2017. The reduction in energy sales and non-regulated fuel for generation and purchased power in Maritime Canada in Q4 2017 reflects the renegotiation of the Bayside Power PPA for the winter of 2017/2018, providing the counterparty with increased dispatch flexibility, while maintaining the net revenue stream for the facility.

Adjusted EBITDA increased $2 million to $66 million in 2017 from $64 million in 2016. Absent the $20 million in prior period state fuel taxes at NEGG, adjusted EBITDA would have decreased $18 million in 2017 compared to 2016. This is mainly due to lower realized energy margins in NEGG in 2017, reflecting more favourable short-term energy hedges in Q1 2016 compared to Q1 2017, lower energy sales volumes due to the unplanned outage at the Bridgeport Facility and less favourable market conditions in Q1 and Q3 2017. These factors were partially offset by higher capacity prices that came into effect for NEGG in June 2017.

Operating Statistics

For the	Sales Volumes (GWh) (1) 2017	Sales Volumes (GWh) (1) 2016	Plant Availability (%) (2) 2017	Plant Availability (%) (2) 2016	Net Capacity Factor (%) (3) 2017	Net Capacity Factor (%) (3) 2016
						Three months ended December 31
New England	**1,413**	1,264	**94.9%**	88.5%	**57.4%**	51.7%
Maritime Canada	**40**	420	**77.8%**	85.5%	**5.6%**	61.0%
Total	**1,453**	1,684	**91.0%**	87.8%	**45.8%**	53.8%

For the	Sales Volumes (GWh) (1) 2017	Sales Volumes (GWh) (1) 2016	Plant Availability (%) (2) 2017	Plant Availability (%) (2) 2016	Net Capacity Factor (%) (3) 2017	Net Capacity Factor (%) (3) 2016
						Year ended December 31
New England	**3,909**	5,221	**81.8%**	90.9%	**40.0%**	54.3%
Maritime Canada	**700**	1,713	**73.0%**	86.7%	**25.0%**	62.5%
Total	**4,609**	6,934	**79.9%**	90.0%	**36.7%**	56.1%

(1) Sales volumes represent the actual electricity output of the plants.

(2) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running. Effectively, it represents 100% availability reduced by planned and unplanned outages.

(3) Net capacity factor is the ratio of the utilization of an asset as compared to its maximum capability, within a particular time frame. It is generally a function of plant availability and plant economics vis-à-vis the market.

NEGG sales volumes, plant availability and net capacity factor were higher quarter-over-quarter due to fewer planned outage hours at Tiverton Power in Q4 2017 compared to Q4 2016.

Maritime Canada sales volumes and net capacity factor were lower quarter-over-quarter reflecting negotiated changes to Bayside Power's PPA for the 2017/2018 winter period. The decrease in plant availability reflects the timing of planned outages at Bayside Power quarter-over-quarter.

NEGG sales volumes, plant availability and net capacity factor were lower year-over-year due to the impact of an unplanned outage at the Bridgeport Facility from mid-March 2017 to mid-June 2017 and less favourable market conditions in 2017 compared to 2016, partially offset by fewer planned outage hours at Tiverton Power in 2017.

Maritime Canada sales volumes, plant availability and net capacity factor were lower year-over-year due to a planned outage at the Bayside Facility in Q2 2017, less favourable market conditions in 2017 compared to 2016 and the negotiated changes to Bayside Power's PPA for the 2017/2018 winter period.

CORPORATE AND OTHER

Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
Operating revenues – regulated gas	**$ 13**	$ 12	**$ 52**	$ 38
Non-regulated operating revenue	**19**	28	**75**	55
Total operating revenue	**$ 32**	$ 40	**$ 127**	$ 93
Intercompany revenue (1)	**10**	10	**39**	39
Income from equity earnings	**26**	20	**96**	86
Interest expense, net (2)	**76**	76	**293**	328
Adjusted contribution to consolidated net income	**$ (1)**	$ (17)	**$ (88)**	$ 2
After-tax mark-to-market gain (loss)	**-**	2	**2**	(114)
Revaluation of US non-regulated deferred income taxes	**(46)**	-	**(46)**	-
Contribution to consolidated net income (loss)	**$ (47)**	$ (15)	**$ (132)**	$ (112)
Adjusted contribution to consolidated earnings per common share – basic	**$ -**	$ (0.08)	**$ (0.41)**	$ 0.01
Contribution to consolidated earnings per common share – basic	**$ (0.22)**	$ (0.07)	**$ (0.62)**	$ (0.65)
Adjusted EBITDA	**$ 45**	$ 25	**$ 136**	$ 262

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

(2) Interest expense, net excludes a pre-tax mark-to-market gain of $3 million year-to-date 2017 (2016 - $ 2 million).

Revaluation of US non-regulated deferred income taxes

Due to the enactment of US Tax Cuts and Jobs Act of 2017, Corporate recorded a non-cash income tax expense resulting from the provisional revaluation of the existing US non-regulated net deferred income tax assets. This provisional revaluation of an existing asset is not the result of any operational or market driven event and therefore management believes excluding from adjusted net income the effect of this provisional revaluation better distinguishes the ongoing operations of the business, and allows investors to better understand and evaluate the Company.

Net Income

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

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income (loss) – 2016	**$ (15)**	**$ (112)**
(Decreased) increased operating revenue - see Operating Revenues below	(8)	34
Increased OM&G quarter-over-quarter due to higher project spend. Decreased costs year-over-year, primarily due to 2016 costs related to the TECO Energy acquisition	(3)	84
Income from equity investments - see Income from Equity Investments below	6	10
2016 gain/loss on sale of APUC common shares, pre-tax	12	(160)
2016 gain on conversion of APUC subscription receipts and dividend equivalents into APUC common shares, pre-tax	-	(63)
Decreased other non-regulated direct costs quarter-over-quarter as a result of lower project activity at Emera Utility Services in Q4 2017. Increased other non-regulated direct costs year-over-year, primarily due to increased project activity at Emera Utility Services	13	(17)
Decreased interest expense - see Interest Expense below	-	35
Revaluation of US non-regulated deferred income taxes due to tax reform	(46)	(46)
After-tax mark-to-market loss primarily related to the 2016 adjustments from forward contracts economically hedging the debenture offering and the translation of the USD cash balance	(2)	116
Other	(4)	(13)
Contribution to consolidated net income (loss) – 2017	**$ (47)**	**$ (132)**

Operating Revenues

Operating revenues decreased $8 million to $32 million in Q4 2017 compared to $40 million in Q4 2016 as a result of decreased project activity at Emera Utility Services. Operating revenues for the year ended December 31, 2017 increased $34 million to $127 million compared to $93 million in 2016. The increase was primarily due to increased project activity year-over-year at Emera Utility Services and funding commitments made to New Mexico related to the TECO Energy acquisition in Q3 2016.

Income from Equity Investments

Income from equity investments are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
APUC - sold in 2016	**$ -**	$ -	**$ -**	$ 18
M&NP	**6**	6	**23**	23
NSPML	**10**	6	**36**	21
LIL	**10**	8	**37**	24
Income from equity investments	**$ 26**	$ 20	**$ 96**	$ 86

Income from equity investments increased $6 million to $26 million in Q4 2017 compared to $20 million in Q4 2016. For the year ended December 31, 2017, income from equity investments increased $10 million to $96 million compared to $86 million in 2016. These variances were a result of higher earnings from the increased equity investment in NSPML and LIL, partially offset by the sale of APUC in 2016.

Interest Expense

Interest expense for the three months ended December 31, 2017 remained unchanged compared to the same period in 2016. For the year ended December 31, 2017, interest expense decreased $35 million to $293 compared to $328 million in 2016 as a result of the conversion of the TECO Energy acquisition related convertible debentures, partially offset by the permanent USD denominated debt related to the TECO Energy acquisition in 2016.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates cash primarily through its investments in various regulated and non-regulated energy related entities and investments. Utility customer bases are diversified by both sales volumes and revenues among customer classes. Emera's non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company's ability to generate 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. Emera's subsidiaries maintain solid credit metrics and are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment.

Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the years ended December 31, 2017 and 2016 include:

Year ended December 31 millions of Canadian dollars	**2017**	2016	$ Change
Cash, cash equivalents and restricted cash, beginning of period	**$ 491**	$ 1,092	$ (601)
Provided by (used in):			
Operating cash flow before changes in working capital	**1,297**	919	378
Change in working capital	**(104)**	134	(238)
Operating activities	**1,193**	1,053	140
Investing activities	**(1,761)**	(9,037)	7,276
Financing activities	**593**	7,448	(6,855)
Effect of exchange rate changes on cash and cash equivalents	**(13)**	(65)	52
Cash, cash equivalents and restricted cash, end of period	**$ 503**	$ 491	$ 12

Cash Flow from Operating Activities

Refer to Consolidated Income Statement and Operating Cash Flow highlights earlier in the document for details.

Cash Flow Used in Investing Activities

Net cash used in investing activities decreased $7,276 million to $1,761 million for the year ended December 31, 2017 compared to $9,037 million in 2016. The decrease was primarily due to the acquisition of TECO Energy in 2016. This was partially offset by an increase in capital spending and proceeds from the sale of APUC common shares in 2016.

Capital expenditures, including AFUDC and net of proceeds from disposal of assets, for the year ended December 31, 2017 were $1,537 million compared to $1,102 million in 2016. The increase was the result of the acquisition of TECO Energy, additional capital spending in NSPI and Corporate offset by a reduction in capital spending at Emera Caribbean. Details of the capital spend are shown below:

- $914 million at Emera Florida and New Mexico (2016 - $573 million);
- $393 million at NSPI (2016 - $309 million);
- $85 million at Emera Maine (2016 - $86 million);
- $72 million at Emera Caribbean (2016 - $87 million);
- $47 million at Emera Energy (2016 - $39 million); and
- $26 million at Corporate and Other (2016 – $8 million).

Cash Flow from Financing Activities

Net cash provided by financing activities decreased $6,855 million to $593 million for the year ended December 31, 2017 compared to $7,448 million in 2016. The decrease was due to the proceeds of the long-term debt issuance and convertible debentures related to the acquisition of TECO Energy in 2016 and proceeds from the long-term debt issuance at ECI in Q4 2016. This was reduced by increased 2017 borrowings under committed credit facilities, an increase in short term borrowings and an increase in equity issued by Emera in 2017.

Working Capital

As at December 31, 2017, Emera's cash and cash equivalents were $438 million (2016 – $404 million) and Emera's investment in non-cash working capital was $322 million (2016 – $301 million). Of the cash and cash equivalents held at December 31, 2017, $174 million was held by Emera's foreign subsidiaries (2016 – $267 million). A portion of these funds are invested in countries that have certain exchange controls, required approvals, and processes for repatriation. Such funds remain available to fund local operating and capital requirements unless repatriated.

Emera's future liquidity and capital needs will be predominately for working capital requirements and capital expenditures in support of growth throughout the businesses, as well as acquisitions, dividends and debt servicing. In addition to using cash generated from operating activities, Emera uses available cash and credit facility borrowings to support normal operations and capital requirements. Emera may reduce short-term borrowings with cash from operations, long-term borrowings, or equity contributions. Emera has credit facilities with varying maturities that cumulatively provide $3.2 billion of credit (see note 23 and note 25 to the consolidated financial statements for additional information regarding the credit facilities).

As a result of US tax reform, an estimated decrease in cash from operations of $50 million to $200 million annually in Emera's US businesses is expected. This decrease is primarily due to expected revenue reductions as a result of lower income tax expense and amortization of the deferred tax regulatory liability at the US regulated utilities. Emera currently pays minimal cash taxes as a result of existing tax loss carryforwards and therefore the reduction in cash revenues is not offset by lower cash tax payments over the near term. This decrease will be partially offset by cash refunds associated with AMT credit carryforwards beginning in 2019. In addition, Tampa Electric has filed to collect storm restoration costs in 2018, which if approved, would offset the decrease in cash associated with tax reform in 2018.

Emera believes that its liquidity is adequate given its expected operating cash flows, capital expenditures, and related financing plans.

Contractual Obligations

As at December 31, 2017, commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2018	2019	2020	2021	2022	Thereafter	Total
Long-term debt principal	$ 741	$ 1,105	$ 646	$ 2,204	$ 469	$ 8,783	$ 13,948
Interest payment obligations (1)	537	598	543	496	451	5,538	8,163
Purchased power (2)	234	216	212	209	206	2,148	3,225
Transportation (3)	451	298	264	184	172	1,339	2,708
Pension and post-retirement obligations (4)	112	38	38	39	39	751	1,017
Fuel and gas supply	527	176	50	41	-	-	794
Capital projects	413	88	-	-	-	-	501
Long-term service agreements (5)	75	65	34	44	35	180	433
Asset retirement obligations	2	1	1	42	1	382	429
Equity investment commitments (6)	15	5	190	-	-	-	210
Leases and other (7)	43	12	10	7	4	61	137
DSM	63	28	18	18	18	-	145
Long-term payable	4	4	5	5	5	5	28
Convertible debentures	-	-	-	-	-	3	3
	$ 3,217	$ 2,634	$ 2,011	$ 3,289	$ 1,400	$ 19,190	$ 31,741

(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, 2017, 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) Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2017. Credited service and earnings are assumed to be crystallized as at December 31, 2017. The Company's contractual obligations for post-retirement (non-pension) benefits assumes members must be age 55 or over (50 for TECO Energy) as at December 31, 2017 to be eligible. As the defined benefit pension plans currently undergoes regular reviews to revise contribution requirements and members are still accruing service under the plans, actual future contributions to the plans will differ from the amounts shown.

(5) 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.

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

(7) 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. The UARB has approved NSPI to pay NSPML approximately $110 million and $111 million in 2018 and 2019, respectively. After 2019, the timing and amounts payable to NSPML will be subject to a regulatory filing with the UARB which will be filed no later than 2019 and closer to the timing of the Muskrat Falls project completion.

Forecasted Gross Consolidated Capital Expenditures

2018 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	$ 242	$ 120 (1)	$ -	$ 44	$ 51	$ -	$ 457
New renewable generation	601	-	-	7	-	-	608
Transmission	62	83	38	7	-	-	190
Distribution	224	103	26	37	-	-	390
Gas transmission and distribution	315	-	-	-	-	-	315
Facilities, equipment, vehicles, and other	138	54	24	13	-	38	267
	$ 1,582	$ 360	$ 88	$ 108	$ 51	$ 38	$ 2,227

(1) Included within NSPI Generation is $55 million in hydro refurbishments.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.2 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	$ 173	$ 727
Emera Florida and New Mexico - in USD - credit facilities	March 2018 - March 2022	1,600	991	609
NSPI – Operating credit facility	October 2021 – Revolver	600	365	235
Emera Maine – in USD – Operating credit facility	September 2019 – Revolver	80	43	37
Other – in USD – Operating credit facilities	Various	32	5	27

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, 2017. Emera's significant covenant is listed below:

	Financial Covenant	Requirement	As at December 31, 2017
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.61:1

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

Emera and its subsidiaries' recent financing activities are discussed below.

Emera

On December 12, 2017, Emera exercised its accordion option under its revolving credit facility to increase the facility from $700 million to $900 million with no other change to existing terms.

Emera Florida and New Mexico

On November 2, 2017, TEC entered into a $300 million USD non-revolving term loan with a maturity date of November 1, 2018. The loan contains customary representations and warranties, events of default, financial and other covenants and bears interest at LIBOR plus a margin.

On November 1, 2017, TECO Energy/Finance repaid a $300 million USD note upon maturity. The note was repaid using funds from existing credit facilities and cash on hand.

On March 22, 2017, TECO Energy/Finance extended the maturity date of its $300 million USD bank credit facility from December 17, 2018 to March 22, 2022 with no significant change in commercial terms from the prior agreement.

On March 22, 2017, TEC extended the maturity date of its $325 million USD bank credit facility from December 17, 2018 to March 22, 2022, and reduced the existing letter of credit facility to $50 million USD from $200 million USD. There were no other significant changes in commercial terms from the prior agreement.

On March 22, 2017, NMGC extended the maturity date of its $125 USD million bank credit facility from December 17, 2018 to March 22, 2022 with no significant change in commercial terms from the prior agreement.

On March 8, 2017, TECO Energy/Finance extended the maturity date of its $400 million USD term bank credit facility from March 14, 2017 to March 8, 2018 with no significant change in commercial terms from the prior agreement.

Emera Maine

On September 27, 2017 Emera Maine completed a 30-year $50 million USD senior unsecured notes issuance. The notes bear interest at a rate of 4.36 per cent and will mature on September 27, 2047. Proceeds were used to repay maturing notes and for general corporate purposes.

BLPC

On September 1, 2017, BLPC's interest rate on their two $20 million BBD secured fixed rate senior notes maturing in 2020 and 2024 were reduced to 4.25 per cent and 5.875 per cent from 6.65 per cent and 6.875 per cent, respectively. Effective October 11, 2017, interest on their $12 million BBD demand loan facility was reduced to 4 per cent from 6.5 per cent.

EBP

On July 4, 2017, Emera Brunswick Pipeline amended its Credit Agreement to extend the maturity from February 2019 to February 2021 with no change to commercial terms from the prior agreement.

NSPI

On June 28, 2017, NSPI amended its operating credit facility to extend the maturity from October 2020 to October 2021 and the debt to capitalization ratio from 0.65:1 to 0.70:1. All other terms of the agreement are the same.

GBPC

On March 21, 2017, GBPC amended its loan agreement with the addition of two non-revolving term credit facilities. There were no significant changes in commercial terms from the prior agreement. The combined total of these new facilities is for up to $45 million USD. At December 31, 2017, the facilities were drawn in full.

Credit Ratings

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

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

On December 22, 2017, DBRS Limited affirmed NSPI's A (low) issuer and issue rating with stable trends.

On December 21, 2017, Moody's Investor Services affirmed Emera's Baa3 issuer rating and Emera US Finance LP's Baa3 guaranteed senior unsecured rating and changed their ratings outlook to negative from stable. 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 4, 2017, S&P Global Ratings affirmed their BBB+ long term corporate credit rating on Emera, NSPI, TECO Energy/Finance, TEC and NMGC and revised their ratings outlook to stable from negative.

Share Capital

Emera

As at December 31, 2017, Emera had 228.77 million (2016 – 210.02 million) common shares issued and outstanding. For the year ended December 31, 2017, 18.6 million common shares were issued (2016 – 10.82 million) for net proceeds of $857 million (2016 – $466 million).

As at December 31, 2017, Emera had 29 million preferred shares issued and outstanding (2016 – 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 three-year period. The cash required in 2018 for defined benefit pension plans is expected to be $97 million (2017 – $109 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 $25 million for 2018 (2017 – $23 million actual).

Defined Benefit Pension Plan Summary

in millions of Canadian dollars					As at December 31, 2017
Plans by region	**TECO Energy Pension Plans**	**NSPI Pension Plans**	**Emera Maine Pension Plans**	**Caribbean Plans**	**Total**
Assets as at December 31, 2017	$ 961	$ 1,263	$ 174	$ 10	$ 2,408
Accounting obligation at December 31, 2017	1,019	1,446	205	13	2,683
Accounting expense during fiscal 2017	$ 22	$ 45	$ 5	$ 1	$ 73

OFF-BALANCE SHEET ARRANGEMENTS

Defeasance

Upon privatization of the former provincially owned Nova Scotia Power Corporation ("NSPC") in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2017 totalled $726 million (2016 – $753 million). The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), 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.

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

Guarantees and Letters of Credit

As at December 31, 2017, Emera had several significant guarantees and letters of credit on behalf of third parties outstanding. The following guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2017.

TECO Coal was sold on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"). Pursuant to the sales agreement, Cambrian is obligated to file, in respect of each mining permit, applications in connection with the change of control with the appropriate governmental entities. As each application is approved, Cambrian is required to post a bond or other appropriate collateral in order to obtain the release of the corresponding bond secured by the TECO Energy indemnity for that permit. As at December 31, 2017, TECO Energy had remaining indemnified bonds totaling $6 million ($5 million USD).

The amounts outlined above represent the maximum theoretical amounts that TECO Energy would be required to pay to the surety companies.

The Company is working with Cambrian on the process to replace the remaining bonds. Pursuant to the securities purchase agreement, Cambrian has the obligation to indemnify and hold TECO Energy harmless from any losses incurred that arise out of the coal mining permits during the period commencing on the closing date through the date all permit approvals are obtained.

As at December 31, 2017, Emera has a standby letter of credit in the amount of $21 million for the benefit of NSP Maritime Link Inc. (“NSPML”) to guarantee the performance of the obligations of the EUS-Rokstad joint venture. Rokstad Power has issued a separate letter of credit for the benefit of Emera for their portion of the work to be performed under the contract. EUS-Rokstad is a joint venture between EUS and Rokstad Power, formed for the purpose of constructing the high voltage direct current components of NSPML’s transmission line. EUS and Rokstad Power are jointly and severally liable for completion of the project. Subsequent to year end, NSPML has drawn the full amount of the letter of credit, which was funded without recourse to Emera.

Emera has standby letters of credit in the amount of $28 million USD for the benefit of secured parties in connection with a refinancing of the Bear Swamp joint venture and also to third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one-year term and are renewed annually as required.

Emera Reinsurance Limited has issued a standby letter of credit to secure its obligations under reinsurance agreements. The letter of credit expires in December 2018 and is renewed annually. The amount committed as of December 31, 2017 was $6 million USD.

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under an unfunded pension plan. The letter of credit expires in June 2018 and is renewed annually. The amount committed as at December 31, 2017 was $51 million.

DIVIDEND PAYOUT RATIO

Emera targets an average dividend payout ratio of 70 to 75 per cent of adjusted net income. Emera Incorporated’s common share dividends paid in 2017 were $2.1325 ($0.5225 in Q1,Q2 and Q3 and $0.5650 in Q4) per common share and $1.9950 ($0.4750 in Q1 and Q2, and $0.5225 in Q3 and Q4) per common share for 2016, representing a payout ratio of 89.6 per cent of adjusted net income in 2017 and 68.2 per cent for 2016.

On September 29, 2017, Emera’s Board of Directors approved an increase in the annual common share dividend rate from $2.09 to $2.26. The first payment at the increased rate was November 15, 2017. Emera has an eight per cent annual dividend growth target from 2019 to 2020.

ENTERPRISE RISK AND RISK MANAGEMENT

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

The Company’s risk management activities are focused on those areas that most significantly impact profitability, quality of income and cash flow. 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, ENL, Emera Maine, BLPC, GBPC, and Domlec must obtain regulatory approval to change electricity rates and/or riders from their respective regulators. Costs and investments can be recovered upon approval by the respective regulator 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 significant shifts in government policy (including shifts in policy which could occur as a result of climate change concerns) and changes in governments. 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.

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. Persons who cannot resolve traffic, toll and tariff issues with Brunswick Pipeline may file a complaint with the NEB. In the absence of a complaint, the NEB does not normally undertake a detailed examination of Brunswick Pipeline's tolls.

In 2017, the US government initiated a renegotiation of NAFTA and the overall effects of the renegotiation are uncertain. It is possible that general economic conditions and the local economies in the provinces and states in which Emera operates might be impacted. Emera is monitoring the status of negotiations and is engaged in the matter through government and industry consultation and collaboration.

Weather and Climate Risk

Shifts in weather patterns affect energy sales and associated revenues and costs. Extreme weather events generally result in increased operating costs associated with restoring service to customers as a result of unplanned outages. Emera responds to outages which occur as a result of significant weather events according to each subsidiary's respective emergency services restoration plan. For certain utilities, restoration costs associated with these significant weather events are recoverable through rates upon regulatory approval. BLPC maintains a Self-Insurance Fund ("SIF") for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC's generating, transmission and distribution systems.

Changes in Environmental Legislation

Emera is subject to regulation by federal, provincial, state, regional and local authorities with regard to environmental matters, primarily related to its utility operations. This includes laws setting greenhouse gases ("GHG") emissions standards and air emissions standards. Emera is also subject to laws regarding waste management, wastewater discharges and aquatic and terrestrial habitats.

Emission reduction requirements are being established by the Government of Canada that will include a national price on carbon in 2018. In the United States, 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's reliance on information technology systems and network infrastructure to manage its business, including controls for interconnected systems of generation, distribution and transmission, exposes the Company to potential risks related to cybersecurity attack. Attacks can occur over the Internet, through malware, viruses, attachments to e-mails, through persons inside of the organization or through persons with access to systems outside of the organization. A cybersecurity attack could disrupt operations, cause loss of important data or compromise customer, employee-related or other critical information or systems, or otherwise adversely affect Emera's business, reputation and financial results and condition.

Despite security measures in place, the Company's systems, assets and information could experience security breaches that could cause system failures, disrupt operations, adversely affect safety, result in loss of service to customers and release of sensitive or confidential information. Should such cybersecurity risks materialize, the Company could suffer costs, losses and damage, all or some of which may not be recoverable through legal, regulatory or other processes. The Company seeks to manage this risk by maintaining a cybersecurity strategy, based on the National Institute of Standards and Technology Cyber Security Framework, to both comply with relevant regulation and sustain industry best-practice governance and capability. The Company provides training to employees regarding cyber risks, including phishing, malware and ransomware to increase awareness of the risks and protect against security breaches.

Energy Consumption Risk

Typical of utilities, Emera's rate-regulated subsidiaries are affected by demand for energy in the areas in which it operates based upon fluctuations in general economic conditions, such as changes in employment levels, personal disposable income, energy prices and housing starts. Customers' focus on energy efficiency also results in changes in energy consumption. Government policies promoting distributed generation and new technology developments enabling those policies, particularly with rooftop solar, have the potential to impact how electricity enters the system and how it is bought and sold. This could negatively impact operations, net earnings and cash flows.

Energy costs and clean energy options have increased demand for products enabling the consumers' ability to self-generate. The Company's rate-regulated subsidiaries are actively involved in all aspects of customer demand, energy efficiency and government policy to ensure that the impact of these activities benefits customers, are not detrimental to the reliability of the energy service the subsidiary provides, and are accommodated through regulations. Additionally, the Company is monitoring the evolution of distributed generation and technology through its strategic initiatives.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates globally, 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 short-term foreign currency derivative instruments to hedge specific transactions. The Company enters into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams, capital expenditures and projects. 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 are included in accumulated other comprehensive income (loss) ("AOCI").

Capital Market and Liquidity Risk

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

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 change to a credit rating as a result of changes in any of these items 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.

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, short-term credit facilities, and ongoing access to capital markets. The Company reasonably expects liquidity sources to exceed ordinary course capital needs.

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. While 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 raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

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 value-at-risk ("VaR") analysis of its exposures. The VaR amount represents an estimate of the potential change in fair value that could occur from changes in market factors within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with physical 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.

Credit Risk

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

Country Risk

Operating revenues outside of Canada constituted 76 per cent (69 per cent from the US and 7 per cent from the Caribbean) of Emera's total operating revenues in 2017 (2016 – 65 per cent, with 55 per cent from the US and 10 per cent from the Caribbean). Emera's investments are currently in regions where the political and economic risk levels are considered by the Company to be acceptable. Emera's operations in some countries may be subject to changes in the rate of economic growth, restrictions on the repatriation of income or capital exchange controls, inflation, the effect of global health, safety and environmental matters or economic conditions and market conditions, and change in financial policy and availability of credit. 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 its commercial relationships risk by monitoring credit risk, as discussed above in Credit Risk, and monitoring of significant developments with its customers, partners and suppliers.

Commodity Price Risk

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

Future Employee Benefit Plan Performance and Funding Risk

Certain Emera subsidiaries have both defined benefit and defined contribution employee benefit plans that cover their employees and retirees. All defined benefit plans are closed to new entrants, with the exception of the TECO Energy Group Retirement Plan. The cost of providing these benefit plans varies depending on the plan provisions, interest rates, investment performance and actuarial assumptions concerning the future. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels, 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

Certain Emera employees are subject to collective labour agreements. Approximately 38 per cent of the full-time and term employees within the Emera labour force are represented by unions.

As at December 31, 2017, approximately 10 per cent of the entire labour force is covered by collective labour agreements that will expire within the next 12 months. Emera seeks to manage this risk through ongoing discussions with local unions. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labor disruption.

Information Technology Risk

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

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. Although a reduction in the corporate income tax rate could result in lower future tax expense and tax payments, it would also reduce the value of the Company's existing deferred tax assets and could result in a charge to earnings if written down. US tax reform legislation was enacted on December 22, 2017. Although some of the specific details have yet to be clarified, this legislation has had a negative impact on the Company's 2017 financial results. Refer to the "Developments" section for further details. 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 and interest rates through contractual protections with counterparties where practicable, as well as by using financial instruments consisting mainly of foreign exchange forwards and swaps, interest rate options and swaps, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. Collectively, these contracts and financial instruments are considered "derivatives".

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

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

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

Derivatives entered into by 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 that any gains or losses resulting from settlement of these derivatives be refunded to or collected from customers in future rates.

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

Hedging Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**December 31 2017**		December 31 2016
Derivative instrument assets (current and other assets)	**$**	**7**	$	10
Derivative instrument liabilities (current and long-term liabilities)		**(7)**		(27)
Net derivative instrument assets (liabilities)	**$**	**-**	$	(17)

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 millions of Canadian dollars				Year ended December 31
		2017		2016
Operating revenues – regulated	**$**	**(10)**	$	(12)
Non-regulated fuel for generation and purchased power		**3**		2
Income from equity investments		**-**		(1)
Effective net gains (losses)	**$**	**(7)**	$	(11)

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 millions of Canadian dollars		**December 31 2017**		December 31 2016
Derivative instrument assets (current and other assets)	**$**	**181**	$	229
Regulatory assets (current and other assets)		**13**		11
Derivative instrument liabilities (current and long-term liabilities)		**(13)**		(12)
Regulatory liabilities (current and long-term liabilities)		**(183)**		(231)
Net asset (liability)	**$**	**(2)**	$	(3)

Regulatory Impact Recognized in Net Income

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

For the millions of Canadian dollars		Year ended December 31 **2017**		 2016
Regulated fuel for generation and purchased power (1)	**$**	**17**	$	2
Net gains (losses)	**$**	**17**	$	2

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

Held-for-trading ("HFT") Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**December 31 2017**		December 31 2016
Derivative instruments assets (current and other assets)	**$**	**63**	$	37
Derivative instruments liabilities (current and long-term liabilities)		**(290)**		(434)
Net derivative instrument assets (liabilities)	**$**	**(227)**	$	(397)

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 millions of Canadian dollars				Year ended December 31
		2017		2016
Non-regulated operating revenues	**$**	**408**	$	68
Non-regulated fuel for generation and purchased power		**12**		(7)
Other income (expenses), net		**-**		(2)
Net gains (losses)	**$**	**420**	$	59

Other Derivatives Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**December 31** **2017**		December 31 2016
Derivative instrument assets (current and other assets)	**$**	**2**	$	-
Derivative instrument liabilities (current and long-term liabilities)		**-**		(2)
Net derivative instrument assets (liabilities)	**$**	**2**	$	(2)

Other Derivatives Recognized in Net Income

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

For the millions of Canadian dollars				Year ended December 31
		2017		2016
Other income (expense)	**$**	-	$	(87)
Interest expense, net		2		2
Total gains (losses)	**$**	**2**	$	(85)

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, 2017 to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

Change in ICFR

In August 2017, Emera upgraded its Enterprise Resource Planning ("ERP") system and other associated financial systems in the Company's Canadian operating entities. This upgrade, which resulted in a material change to the internal controls over financial reporting, was designed to automate certain manual processes and standardize business processes and reporting across the impacted entities. Emera and its affiliates have made appropriate changes to internal controls and procedures, as is expected with a major system implementation, and have concluded that none of the changes resulting from the implementation materially alter the effectiveness of the ICFR.

There were no other changes in the Company's ICFR during the quarter ended December 31, 2017, 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 Tampa Electric, PGS, NMGC, NSPI, Emera Maine, BLPC, GBPC, Domlec, NSPML and Brunswick Pipeline may differ from accounting policies for non-rate-regulated companies, which are subject to examination and approval by their respective regulators. These accounting policy differences occur when the regulators render their decisions on rate applications or other matters, and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on the expectation of the future actions of the regulators. 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 since a change in these assumptions may result in a material impact on reported assets, liabilities and the results of operations.

Emera has recorded $1,376 million (2016 - $1,322 million) of regulatory assets and $2,468 million (2016 - $1,639 million) of regulatory liabilities as at December 31, 2017.

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 cost of removal of property, plant and equipment upon retirement. The companies accrue for removal costs 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 is $894 million at December 31, 2017 (2016 - $990 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.

Emera'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 (currently 8.1 years). Emera'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:

	2017		2016	
	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	**4.16 %**	**7.00 %**	3.72 %	7.00 %
TECO Energy Group Supplemental Executive Retirement Plan	**3.37**%/**3.25 %**	**N/A**	2.64 %	N/A
TECO Energy Group Benefit Restoration Plan	**3.64 %**	**N/A**	3.12 %	N/A
TECO Energy Post-retirement Health and Welfare Plan	**4.28 %**	**N/A**	3.85 %	N/A
New Mexico Gas Company Retiree Medical Plan	**4.28 %**	**7.00** %	3.85 %	5.75 %
NSPI	**3.84 %**	**5.75 %**	4.00 %	5.75 %
Bangor Hydro (1)	**4.04 %**	**6.55 %**	4.25 %	6.75 %
MPS (1)	**3.91 %**	**6.55 %**	4.10 %	6.75 %
GBPC	**4.25 %**	**6.00 %**	4.75 %	6.00 %

(1) 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 is $105 million in 2017 (2016 - $90 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 2017 benefit cost of $9 million and $6 respectively (2016 - $7 million and $4 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 of related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2017, unbilled revenues totalled $278 million (2016 – $270 million) on total annual operating revenues of $6,226 million (2016 – $4,277 million).

Property, Plant and Equipment

Property, plant and equipment represents 59 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.

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 $833 million for the year ended December 31, 2017 (2016 – $560 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. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. 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 bypasses 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.

Application of the goodwill impairment test requires management judgment. Significant assumptions used in these fair value analyses 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, 2017, the Company had goodwill with a total carrying amount of $5,805 million (December 31, 2016 – $6,213 million). The change in the carrying value from 2016 to 2017 is a result of the strengthening Canadian 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.

Determining the fair market value of goodwill is susceptible to changes 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 significant assumptions, including growth rates, utility sector market performance and transactions, projected operating and capital cash flows from the affiliates businesses, could also negatively impact goodwill in the future.

No impairment provisions with respect to goodwill were required for either 2017 or 2016.

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 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.

In 2017 an estimated impairment provision was taken on assets in Domlec. Emera's portion of this provision is immaterial. See "Developments – Domlec" for further details. No impairment provisions with respect to long-lived assets were required for 2016.

Income Taxes

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

The Company believes that 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 enactment of Tax Cuts and Jobs Act on December 22, 2017, Emera recorded a material revaluation of the Company's US deferred tax assets and liabilities at December 31, 2017. Some of the specific details of the Act have yet to be clarified and therefore, management has estimated the implications of the Act based on the best information available. Any change in assumptions could have a material impact on the results of Emera. See "Developments – US Tax Reform" for further details.

Asset Retirement Obligations

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 thermal assets, hydro assets, wind assets, combustion turbines, transmission and distribution assets, 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.

As at December 31, 2017, the AROs recorded on the balance sheet were $172 million (2016 – $170 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $438 million, which will be incurred between 2018 and 2061. The majority of these costs will be incurred between 2028 and 2050.

Capitalized Overhead

As required by their respective regulators, Tampa Electric, PGS, NMGC, NSPI, Emera Maine, BLPC, GBPC, Domlec and NSPML capitalize overhead costs that are not directly attributable to specific utility assets, but to the overall capital expenditure program. The methodology for the calculation of capitalized overhead is approved by their respective regulator. For the year ended December 31, 2017, $156 million of overhead costs (2016 – $111 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

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

Level Determinations and Classifications

Emera uses the Level 1, 2, 3 and NAV 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 Emera 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 2017, are described as follows:

Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows
In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows*. The standard provides guidance regarding the classification of certain cash receipts and cash payments on the statement of cash flows, where specific guidance is provided for issues not previously addressed. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. The Company has early adopted the standard with no impact on the consolidated financial statements as a result of implementation of this standard.

Restricted Cash on the Statement of Cash Flows
In November 2016, the FASB issued ASU 2016-18, *Restricted Cash on the Statement of Cash Flows*. The standard requires the Company to show the changes in total cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. Transfers between cash and cash equivalents and restricted cash and restricted cash equivalents are no longer presented in the statement of cash flows. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. The Company has early adopted this standard. This change in accounting policy has increased net cash used in investing activities by $22 million for the year ended December 31, 2017 (2016 – a decrease of $68 million) within the Consolidated Statement of Cash Flows. Changes in restricted cash are now disclosed within the Consolidated Statement of Cash Flows for all years presented. Restricted cash was $65 million at December 31, 2017 (2016 – $87 million).

Simplifying the Test for Goodwill Impairment
In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment*. The standard provides guidance to simplify the subsequent measurement of goodwill by eliminating the second step of the quantitative test. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019, with early adoption permitted and is required to be applied prospectively. The Company has early adopted the standard with no impact on the consolidated financial statements as a result of implementation of this standard.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by 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 insignificant impact on the consolidated financial statements.

Revenue from Contracts with Customers
In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which creates a new, principle-based revenue recognition framework, codified as Accounting Standards Codification ("ASC") Topic 606. The FASB issued amendments to ASC Topic 606 during 2016 to clarify certain implementation guidance and to reflect scope improvements and practical expedients. The guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and will allow for either full retrospective adoption or modified retrospective adoption. The Company will adopt this guidance effective January 1, 2018, using the modified retrospective approach.

The Company implemented a revenue recognition project plan in 2016. In Q1 2017, the Company concluded that the accounting for contributions in aid of construction will be out of the scope of the new standard. In Q2 2017, the Company completed an analysis of material regulated revenue streams and collectability risk and concluded that there will be no material changes on adoption of this standard. In Q3 2017, the Company completed an analysis of material unregulated revenue streams and concluded that there will be no material changes on adoption of this standard. The Company also evaluated the disclosure requirements and determined that the disaggregation of revenue information required by the new standard will not have a significant impact on the Company's information gathering processes and procedures as the revenue information required by the standard is consistent with historical revenue information gathered by the Company for financial reporting purposes. The Company continues to monitor the assessment of ASC Topic 606 by the AICPA Power and Utilities Revenue Recognition Task Force for developments.

Recognition and Measurement of Financial Assets and Financial Liabilities
In January 2016, the FASB issued ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. This guidance will be 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 will elect 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 a similar investment 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 increase in volatility of Other income (expense), net as a result of the remeasurement of equity investments is not expected to be significant. The Company will adopt this guidance effective January 1, 2018 with a cumulative-effect adjustment of approximately $3 million to retained earnings in the Consolidated Balance Sheet.

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 existing 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.

In January 2018, the FASB issued an amendment to ASC Topic 842 which permits companies to elect an optional transition practical expedient to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. In November 2017, the FASB voted to amend ASC Topic 842 to allow companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The amendment is expected to be finalized in Q1 2018.

The Company is in the process of evaluating the impact of adoption of this standard on its financial statements and disclosures. In Q3 2017, the Company implemented a project plan. In Q4 2017, the Company began execution of the project plan, including training sessions with key stakeholders throughout the organization and gathering detailed information on existing lease arrangements. This includes evaluating the available practical expedients, calculating the lease asset and liability balances associated with individual contractual arrangements and assessing the disclosure requirements. The Company 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.

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 will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted and is required to be applied prospectively. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

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 will be eligible for capitalization as property, plant and equipment under this guidance. This guidance will be 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 limiting capitalization. In Q4, 2017 the Company completed an analysis of the impact of the adoption of this standard on the consolidated financial statements and concluded that the impact on the balance sheet will be minimal. The other components of net benefit cost that will be required to be presented outside of income from operations in the Consolidated Statements of Income on adoption are $28 million for the year ended December 31, 2017. The Company will adopt this guidance effective January 1, 2018.

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 Company is currently evaluating the impact of the adoption of this standard on the consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q4 2017**	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Operating revenues	**$ 1,473**	$ 1,427	$ 1,469	$ 1,857	$ 1,513	$ 1,387	$ 499	$ 877
Net income (loss) attributable to common shareholders	**(228)**	81	101	312	70	(95)	208	44
Adjusted net income attributable to common shareholders	**137**	118	117	152	104	14	238	120
Earnings per common share – basic	**(1.06)**	0.38	0.47	1.48	0.34	(0.52)	1.39	0.30
Earnings per common share – diluted	**(1.06)**	0.38	0.47	1.47	0.34	(0.52)	1.38	0.30
Adjusted earnings per common share – basic	**0.64**	0.55	0.55	0.72	0.51	0.08	1.59	0.81

Quarterly operating revenues and adjusted net income attributable to common shareholders are affected by seasonality. Historically, the first quarter has generally been the strongest because a significant portion of the Company's operations are in northeastern North America, where winter is the peak electricity usage season. However, with the addition of Emera Florida and New Mexico, the third quarter has provided stronger 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.