Management’s Discussion & Analysis

As at May 9, 2019

Management’s Discussion & Analysis (“MD&A”) provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments (“Emera”) during the first quarter of 2019 relative to the same quarter in 2018; and its financial position as at March 31, 2019 relative to December 31, 2018. Throughout this discussion, “Emera Incorporated”, “Emera” and “Company” refer to Emera Incorporated and all of its consolidated subsidiaries and investments.

This discussion and analysis should be read in conjunction with the Emera Incorporated unaudited condensed consolidated interim financial statements and supporting notes as at and for the three months ended March 31, 2019; and the Emera Incorporated annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2018. Emera follows United States Generally Accepted Accounting Principles (“USGAAP” or “GAAP”).

Effective January 1, 2019, Emera has revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations. The five new reportable segments are:

- **Florida Electric Utility**, which consists of Tampa Electric;
- **Canadian Electric Utilities**, which includes Nova Scotia Power Inc. and Emera Newfoundland and Labrador Holdings Inc., a holding company with equity investments in NSP Maritime Link Inc. and Labrador-Island Link Limited Partnership;
- **Other Electric Utilities**, which includes Emera Maine and Emera Caribbean;
- **Gas Utilities and Infrastructure**, which includes Peoples Gas System, New Mexico Gas Company, Inc., SeaCoast Gas Transmission, LLC; Emera Brunswick Pipeline Company Limited and an equity investment in Maritimes & Northeast Pipeline LLC; and
- **Other**, which includes Emera Energy, Emera Utility Services Inc. and corporate holding and financing companies.

All comparative segment financial information for the three months ended March 31, 2018 has been restated with no impact to reported consolidated results.

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 and investments 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")
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")
Peoples Gas System ("PGS") – Gas Division of TEC	FPSC
New Mexico Gas Company, Inc. ("NMGC")	New Mexico Public Regulation Commission ("NMPRC")
SeaCoast Gas Transmission, LLC ("SeaCoast")	FPSC
Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline")	National Energy Board ("NEB")
Equity Investments	
NSP Maritime Link Inc. ("NSPML")	UARB
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")
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline LLC ("M&NP")	NEB and FERC

All amounts are in Canadian dollars ("CAD"), except for the Florida Electric Utility, Other Electric Utilities and Gas Utilities and Infrastructure sections of the MD&A, which are reported in US dollars ("USD"), unless otherwise stated.

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

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FORWARD-LOOKING INFORMATION

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations are discussed in the “Business Overview and Outlook” section of the MD&A and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; pricing and timing of select asset sales; future dividend growth; timing and costs associated with certain capital investment; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty credit risk; commercial relationship risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; market energy sales prices; labour relations; and availability of labour and management resources.

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

INTRODUCTION AND STRATEGIC OVERVIEW

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

Emera’s investment in rate-regulated businesses is concentrated in Florida and Nova Scotia. These jurisdictions provide generally stable regulatory and economic environments.

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

Emera has a $6.5 billion capital investment plan over the 2019 to 2021 period, including investing $1.4 billion ($1 billion USD) in Florida for the completion of Tampa Electric's 600 megawatts ("MW") of new solar generation and the modernization of the Big Bend Power Station. This planned capital investment is being funded primarily through internally generated cash flows, debt raised at the operating company level and select asset sales. Equity capital markets, including the issuance of common and preferred equity and the dividend reinvestment plan will continue to support the Company's future capital investments. Maintaining investment-grade credit ratings is a key priority of management.

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

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

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

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

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

NON-GAAP FINANCIAL MEASURES

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

Adjusted Net Income

Emera calculates an adjusted net income measure by excluding the effect of:

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

Management believes excluding from net income the effect of these mark-to-market valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows and ongoing operations of the business, and allows investors to better understand and evaluate the business. Management and the Board of Directors exclude these mark-to-market adjustments for evaluation of performance and incentive compensation.

Refer to the "Consolidated Financial Review" section and the "Financial Highlights" sections for Other Electric Utilities and Other segments, for further details on mark-to-market adjustments.

The following reconciles reported net income attributable to common shareholders, to adjusted net income attributable to common shareholders; and reported earnings per common share – basic, to adjusted earnings per common share – basic:

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2019**	 2018
Net income attributable to common shareholders	**$ 312**	$ 271
After-tax mark-to-market gain	**$ 88**	$ 69
Adjusted net income attributable to common shareholders	**$ 224**	$ 202
Earnings per common share – basic	**$ 1.32**	$ 1.17
Adjusted earnings per common share – basic	**$ 0.95**	$ 0.87

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 reflect Emera's specific operating performance. These measures are not intended to replace "Net income attributable to common shareholders" which, as determined in accordance with GAAP, is an indicator of operating performance.

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

For the millions of Canadian dollars	Three months ended March 31 **2019**	2018
Net income (1)	**$ 324**	$ 278
Interest expense, net	**189**	175
Income tax expense	**82**	65
Depreciation and amortization	**224**	223
EBITDA	**819**	741
Mark-to-market gain, excluding income tax and interest	**126**	100
Adjusted EBITDA	**$ 693**	$ 641

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Q1 Earnings

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

After-tax mark-to-market gains increased $19 million to $88 million in 2019 compared to $69 million in 2018, mainly due to changes in Emera Energy's existing positions on gas contracts and a larger reversal of mark-to-market losses in 2019 compared to 2018, partially offset by higher amortization of gas transportation assets in 2019.

Consolidated Financial Highlights by Business Segment

For the millions of Canadian dollars	Three months ended March 31 **2019**	2018
Adjusted Net Income		
Florida Electric Utility	**$ 61**	$ 60
Canadian Electric Utilities	**96**	90
Other Electric Utilities	**16**	15
Gas Utilities and Infrastructure	**67**	53
Other	**(16)**	(16)
Adjusted net income attributable to common shareholders	**$ 224**	$ 202
After-tax mark-to-market gain	**88**	69
Net income attributable to common shareholders	**$ 312**	$ 271

The following table highlights the significant changes in adjusted net income from 2018 to 2019.

For the millions of Canadian dollars	Three months ended March 31
Adjusted net income – 2018	**$ 202**
Gas Utilities and Infrastructure	14
Gain on sale of property in Florida	10
Canadian Electric Utilities	6
Other variances	(8)
Adjusted net income – 2019	**$ 224**

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

For the millions of Canadian dollars	Three months ended March 31 **2019**	 2018
Operating cash flow before changes in working capital	**$ 418**	$ 444
Change in working capital	**(16)**	(11)
Operating cash flow	**$ 402**	$ 433
Investing cash flow	**$ 298**	$ (387)
Financing cash flow	**$ (35)**	$ (124)

As at millions of Canadian dollars	**March 31 2019**	December 31 2018
Total assets	**$ 31,799**	$ 32,314
Total long-term debt (including current portion)	**$ 14,531**	$ 15,411

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

Consolidated Income Statement Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2019**	 2018	Variance
Operating revenues	**$ 1,818**	$ 1,807	$ 11
Operating expenses	**1,276**	1,317	41
Income from operations	**542**	490	52
Income from equity investments	**40**	37	3
Other income (expenses), net	**13**	(9)	22
Interest expense, net	**189**	175	(14)
Income tax expense	**82**	65	(17)
Net income	**324**	278	46
Net income attributable to common shareholders	**312**	271	41
After-tax mark-to-market gain	**88**	69	19
Adjusted net income attributable to common shareholders	**$ 224**	$ 202	$ 22
Earnings per common share – basic	**$ 1.32**	$ 1.17	$ 0.15
Earnings per common share – diluted	**$ 1.32**	$ 1.17	$ 0.15
Adjusted earnings per common share – basic	**$ 0.95**	$ 0.87	$ 0.08
Dividends per common share declared	**$ 0.5875**	$ 0.5650	$ 0.0225
Adjusted EBITDA	**$ 693**	$ 641	$ 52

Operating Revenues

For the first quarter of 2019, operating revenues increased $11 million compared to the first quarter of 2018. Absent increased mark-to-market gains of $23 million, operating revenues decreased $12 million due to:

- $35 million decrease at Florida Electric Utility due to lower base rates, reflecting the impact of US tax reform, lower clause recoveries and unfavourable weather. These were partially offset by higher revenues related to in-service solar generation projects, customer growth and the impact of a weaker Canadian dollar; and
- $15 million decrease at Emera Energy due to lower marketing and trading margin reflecting less favourable market conditions relative to the first quarter of 2018.

These impacts were partially offset by increases of:

- $19 million at Canadian Electric Utilities as a result of increased sales volumes at NSPI due to weather and increased fuel related pricing, partially offset by the impact of the Maritime Link assessment; and
- $16 million at Gas Utilities and Infrastructure as a result of the impact of a weaker Canadian dollar, increased sales volumes due to colder weather in New Mexico and increased customers at PGS. These were partially offset by lower base rates reflecting the impact of US tax reform and less favourable weather at PGS.

Operating Expenses

For the first quarter of 2019, operating expenses decreased $41 million compared to the first quarter of 2018. Absent increased mark-to-market losses of $2 million, operating expenses decreased $43 million due to:

- $39 million decrease at Florida Electric Utility as a result of the change in generation mix and decreased operating, maintenance and general ("OM&G") expenses due to the regulatory agreement to net storm costs and tax reform benefits in 2018. These were partially offset by the impact of a weaker Canadian dollar; and
- $14 million decrease in the Other segment primarily as a result of lower depreciation due to classification of New England Gas Generation ("NEGG') as held for sale.

These impacts were partially offset by an increase of:

- $12 million at Canadian Electric Utilities, primarily due to increased fuel for generation and purchased power at NSPI as a result of increased commodity prices and sales volumes.

Other Income (Expenses), Net

The increase in other income (expenses), net for the first quarter in 2019, compared to the first quarter of 2018, was primarily due to the gain on sale of property in Florida.

Income Tax Expense

The increase in income tax expense for the first quarter of 2019 compared to the first quarter of 2018 was due to increased income before provision for income taxes.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For the first quarter of 2019, net income attributable to common shareholders was favourably impacted by the $19 million increase in after-tax mark-to-market gains primarily related to Emera Energy. Absent the favourable mark-to-market changes, adjusted net income attributable to common shareholders increased $22 million. The increase was due to higher contribution from the Gas Utilities and Infrastructure segment, higher contribution from Canadian Electric Utilities, specifically NSPI, and a gain on sale of property in Florida.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic and adjusted earnings per common share – basic were higher for the first quarter due to higher earnings as discussed above.

Effect of Foreign Currency Translation

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

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

Results of 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 2019 and 2018 are as follows:

	Three months ended March 31		Year ended December 31
	2019	2018	2018
Weighted average CAD/USD exchange rate	**$ 1.33**	$ 1.26	$ 1.30
Period end CAD/USD exchange rate	**$ 1.34**	$ 1.29	$ 1.36

The weakening of the Canadian dollar increased earnings by $13 million and adjusted earnings by $8 million in Q1 2019 compared to Q1 2018.

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 March 31 2019	2018
Florida Electric Utility	**$ 46**	$ 48
Other Electric Utilities	**12**	12
Gas Utilities and Infrastructure (1)	**45**	36
	103	96
Other segment (2)	**(16)**	(3)
Total (3)	**$ 87**	$ 93

(1) Includes US dollar net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's US dollar adjusted net income from Emera Energy Services, NEGG and Bear Swamp and interest expense on Emera Inc.'s US dollar denominated debt.
(3) Amounts above do not include the impact of mark-to-market.

BUSINESS OVERVIEW AND OUTLOOK

Effective January 1, 2019, Emera has revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations.

The five new reportable segments are:

- Florida Electric Utility;
- Canadian Electric Utilities;
- Other Electric Utilities;
- Gas Utilities and Infrastructure; and
- Other.

Florida Electric Utility

Florida Electric Utility consists of Tampa Electric, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida.

Tampa Electric anticipates earning within its allowed ROE range in 2019 and expects rate base and earnings to be higher than prior years. Tampa Electric expects customer growth rates in 2019 to be consistent with 2018, reflective of economic growth in Florida. Assuming normal weather in 2019, Tampa Electric sales volumes are expected to be consistent with 2018 which benefited from favourable weather.

In September 2017, Tampa Electric was impacted by Hurricane Irma and incurred restoration costs of approximately $102 million USD. On March 1, 2018, the FPSC approved a settlement agreement filed by Tampa Electric allowing the utility to net the amount of storm cost recovery against its return of estimated 2018 US tax reform benefits to customers. On April 9, 2019, Tampa Electric reached a proposed settlement agreement with consumer parties regarding eligibility of storm costs. If the settlement is approved by the FPSC, Tampa Electric will refund $12 million USD to customers in January 2020, resulting in minimal impact to earnings. A decision by the FPSC is anticipated in Q2 2019.

In 2019, capital expenditures in the Florida Electric Utility segment are expected to be approximately $1.0 billion USD (2018 - $940 million USD), including allowance for funds used during construction ("AFUDC"). Capital projects include supporting normal system reliability and growth, including investments in the modernization of the Big Bend Power Station, solar projects and advanced metering infrastructure ("AMI"). AFUDC will be earned on these projects during the construction periods.

Canadian Electric Utilities

Canadian Electric Utilities includes:

- NSPI, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and the primary electricity supplier to customers in Nova Scotia; and
- ENL, a holding company with equity investments in NSPML and LIL, two transmission investments related to the development of an 824 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador.
    - The Maritime Link entered service on January 15, 2018 and provides for the transmission of energy between Newfoundland and Nova Scotia, as well as improved reliability and ancillary benefits, supporting the efficiency and reliability of both provinces. The Maritime Link will transmit at greater capacity when the Lower Churchill hydroelectricity generation project is complete.
    - Construction of the LIL is complete and Nalcor Energy ("Nalcor") recognized the first flow of energy from Labrador to Newfoundland in June 2018. Nalcor continues to work towards commissioning the LIL, which it forecasts to complete in 2020.

NSPI

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

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

The Government of Canada has laws and regulations that would compel the closure of coal plants before the end of their economic life and at the latest by 2030. The Province of Nova Scotia has enacted laws and regulations that have been found to be equivalent to the federal regulations. Recently, the proposed renewal of the Canada-Nova Scotia Equivalency Agreement was released for public comment on March 29, 2019, with comments due by May 29, 2019. NSPI expects the Equivalency Agreement to be finalized in 2019. This agreement, as proposed, will allow NSPI to achieve compliance with federal greenhouse gas emissions regulations through 2029 by meeting provincial legislative and regulatory requirements as these requirements are deemed to be equivalent to the federal regulations. Efforts are now focused on the development of an Equivalency Agreement that extends to 2040 recognizing equivalent outcomes between federal and provincial environmental laws and regulations.

NSPI has completed registration under the Nova Scotia Cap-and-Trade Program Regulations and received its 2019 granted credits in April 2019. These 2019 credits will be used in 2019 or allocated to other years in the initial four-year compliance period of 2019 through 2022. NSPI anticipates that any prudently incurred costs required to comply with the Government of Canada's Pan-Canadian Framework on Clean Growth and Climate Change, and the Nova Scotia Cap-and-Trade Program Regulations, will be recoverable from customers under NSPI's regulatory framework.

NSPI continues to advance its "Coal to Clean" strategy. To date, carbon dioxide reductions of over 30 per cent have been achieved, exceeding the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change target for a 30 per cent reduction from 2005 levels by 2030.

In 2019, NSPI expects to invest approximately $350 million (2018 - $348 million), including AFUDC, in capital projects to support system reliability and AMI.

ENL

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

NSPML

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

In 2019, NSPML expects to invest approximately $25 million in capital related to construction close-out costs.

LIL

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera’s current equity investment is $545 million, and is forecasted to be $579 million by the end of 2019, comprised of $410 million in equity contribution and an estimated $169 million of accumulated equity earnings. Emera’s total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $600 million after all Lower Churchill projects, including Muskrat Falls, are completed. Nalcor is forecasting these projects to be completed in the second half of 2020.

Cash earnings and return of equity are forecasted by Nalcor to begin in 2020 and until that point Emera will continue to record AFUDC earnings.

Other Electric Utilities

Other Electric Utilities includes:

- Emera Maine, a regulated transmission and distribution electric utility in the State of Maine. On March, 25, 2019, Emera announced an agreement to sell Emera Maine. The transaction is expected to close in late 2019, subject to regulatory approvals. Refer to the “Developments” section for further details.
- Emera (Caribbean) Incorporated (“ECI”), a holding company with regulated electric utilities, BLPC, a vertically integrated regulated electric utility on the island of Barbados, and GBPC, a vertically integrated regulated electric utility on Grand Bahama Island. ECI also holds a:
  - a 51.9 per cent interest in Domlec, a vertically integrated regulated electric utility on the island of Dominica; and
  - a 19.1 per cent equity interest in Lucelec, a vertically integrated regulated electric utility on the island of St. Lucia.

Other Electric Utilities’ earnings are anticipated to increase over the prior year. The sale of Emera Maine is expected to occur in late 2019, resulting in approximately a year of earnings contribution. Emera Maine’s 2019 rate base is expected to grow modestly due to ongoing investment in transmission and distribution infrastructure, resulting in modest growth in earnings. Earnings from ECI’s utilities in 2019 are expected to be consistent with 2018.

In 2019, capital expenditures in the Other Electric Utilities segment are expected to be approximately $190 million USD (2018 – $144 million USD). Emera Maine will invest primarily in transmission and distribution projects supporting normal system reliability. ECI’s utilities are forecasting capital investment in new, efficient oil-based generation and renewable generation.

Gas Utilities and Infrastructure

Gas Utilities and Infrastructure includes:

- PGS, a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas serving customers in Florida;
- NMGC, a regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas serving customers in New Mexico;
- SeaCoast, a regulated intrastate natural gas transmission company offering services in Florida;
- Brunswick Pipeline, a regulated 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick, to markets in the northeastern United States; and
- Emera's non-consolidated investment in M&NP.

Gas Utilities and Infrastructure earnings are anticipated to increase over the prior year. PGS anticipates earning within its allowed ROE range in 2019 and expects rate base and earnings to be higher than prior years. PGS expects customer growth rates in 2019 to be consistent with 2018, reflective of economic growth in Florida and the optimization of existing opportunities as the utility increases its market penetration in Florida. PGS sales volumes are expected to increase at a lower rate in 2019, as 2018 energy sales benefited from favourable weather. NMGC expects earnings and rate base to be higher than prior years. NMGC first quarter earnings in 2019 were higher than last year due to colder weather throughout the quarter. Customer growth rates are expected to be consistent with 2018, reflecting expectations for housing starts and new connections.

On February 26, 2018, NMGC filed a rate case, including the impact of tax reform. A decision by the NMPRC on the rate case and the refund of tax reform benefits realized from January 1, 2018 to the date rates are in effect is expected in Q2 2019.

In 2019, capital expenditures in the Gas Utilities and Infrastructure segment are expected to be approximately $360 million USD (2018 - $254 million USD), including AFUDC. PGS will make investments to expand its system and support customer growth. NMGC will complete planning phases of the Santa Fe Mainline Looping project in 2019, and will continue to invest in system improvements.

Other

The Other segment includes those business operations that in a normal year are below the required threshold for reporting as separate segments; and corporate expense and revenue items that are not directly allocated to the operations of Emera's subsidiaries and investments.

Business operations in Other include:

- Emera Energy, which consists of:
  - 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. In March 2019, Emera completed the sale of the NEGG and Bayside facilities. Refer to the "Developments" section for further details; and
  - an equity investment in a 50.0 per cent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts.
- Emera Utility Services, a utility services contractor primarily operating in Atlantic Canada.

Corporate items included in the Other segment are certain corporate-wide functions including executive management, strategic planning, treasury services, legal, financial reporting, tax planning, corporate business development, corporate governance, investor relations, risk management, insurance, acquisition and disposition related costs, gains or losses on select assets sales, and corporate human resource activities. It includes interest revenue on intercompany financings recorded in “Intercompany revenue” and interest expense on corporate debt in both Canada and the US. It also includes costs associated with corporate activities that are not directly allocated to the operations of Emera’s subsidiaries and investments.

Earnings from EES are generally dependent on market conditions. In particular, volatility in electricity and natural gas markets, which can be influenced by weather, local supply constraints and other supply and demand factors, can provide higher levels of margin opportunity. The business is seasonal, with Q1 and Q4 generally providing the greatest opportunity for earnings. Under normal market conditions, the business is generally expected to deliver adjusted net earnings of $15 to $30 million USD ($45 to $70 million USD of margin), with the opportunity for upside when market conditions present.

The Other segment is expected to contribute positively to earnings in 2019 due to the sale of Emera Maine, with a material gain expected to be recognized in earnings at closing. Absent this gain, the adjusted net loss from the Other segment is expected to increase over the prior year, primarily due to the sale of the NEGG facilities, resulting in only three months of earnings contribution in 2019; and higher corporate costs in 2019. Corporate costs are expected to be higher due to increased preferred dividend expense as a result of additional preferred shares issued in 2018, and lower tax recoveries due to the change in Florida state tax apportionment factors that resulted in the remeasurement of certain deferred tax balances in 2018.

In 2019, capital expenditures in the Other segment are expected to be approximately $50 million (2018 - $75 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Condensed Consolidated Balance Sheets between December 31, 2018 and March 31, 2019 include:

millions of Canadian dollars	Total Increase (Decrease)	Increase (Decrease) due to Emera Maine Held for Sale classification (1)	Other Increase (Decrease)	Explanation of Other Increase (Decrease)
Assets				
Cash and cash equivalents	**$ 663**	**$ -**	**$ 663**	Increased due to proceeds from the sale of the NEGG and Bayside facilities and cash from operations, partially offset by additions of property, plant and equipment and dividends on common stock.
Inventory	**(75)**	**(8)**	**(67)**	Decreased due to seasonal business trends at Emera Energy and settlement of emission credits at NEGG.
Regulatory assets (current and long-term)	**(84)**	**(134)**	**50**	Increased primarily due to deferred income tax regulatory asset at NSPI and an increase in solar investment tax credits at Tampa Electric.
Assets held for sale (current and long-term), net of liabilities	**(98)**	**710**	**(808)**	Decreased due to completion of the sale of the NEGG facilities.
Property, plant and equipment, net of accumulated depreciation and amortization	**(1,346)**	**(1,288)**	**(58)**	Decreased due to the impact of a stronger CAD on the translation of Emera's foreign affiliates and the sale of the Bayside facility, partially offset by additions at the regulated utilities.
Goodwill	**(282)**	**(152)**	**(130)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Receivables and other assets (current and long-term)	**(150)**	**(85)**	**(65)**	Decreased due to lower commodity prices and lower cash collateral positions at Emera Energy, partially offset by higher gas transportation assets at Emera Energy.
Liabilities and Equity				
Short-term debt and long-term debt (including current portion)	**(716)**	**(487)**	**(229)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates and a repayment of Emera's committed credit facilities. These were partially offset by increased borrowings under Tampa Electric's committed credit facilities.
Accounts payable	**(327)**	**(53)**	**(274)**	Decreased due to timing of accounts payable payments at Tampa Electric, NSPI, and NMGC, lower cash collateral on derivative instruments at NSPI and lower commodity prices at Emera Energy.
Deferred income tax liabilities, net of deferred income tax assets	**(221)**	**(199)**	**(22)**	No significant change after removing impact of Emera Maine held for sale classification.
Derivative instruments (current and long-term)	**(122)**	**-**	**(122)**	Decreased due to the reversal of 2018 asset management agreements, partially offset by new contracts at Emera Energy.
Regulatory liabilities (current and long-term)	**(230)**	**(165)**	**(65)**	Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign affiliates and deferrals related to derivative instruments at NSPI.

Pension and post-retirement liabilities	**(86)**	**(74)**	**(12)**	No significant change after removing impact of Emera Maine held for sale classification.
Other liabilities (current and long-term)	**127**	**(13)**	**140**	Increased due to investment tax credits related to solar projects at Tampa Electric and timing of interest payments on long-term debt.
Common stock	**83**	**-**	**83**	Increased due to the dividend reinvestment plan and an increase in options exercised.
Accumulated other comprehensive income	**(121)**	**-**	**(121)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Retained earnings	**174**	**-**	**174**	Increased due to net income in excess of dividends paid.

(1) On March 25, 2019, Emera announced the sale of Emera Maine. As at March 31, 2019, Emera Maine's assets and liabilities were classified as held for sale. Refer to the "Developments" section and note 4 in the condensed consolidated financial statements for further details.

DEVELOPMENTS

Removal of Legislative Restriction on Non-Canadian Resident Ownership of Emera Shares

On April 12, 2019, amendments to the Nova Scotia Power Privatization Act and the Nova Scotia Power Reorganization (1998) Act were enacted, removing the legislative restriction preventing non-Canadian residents from holding more than 25 per cent of Emera voting shares, in aggregate. Shareholder approval will be required for Emera to amend its articles of association to remove this restriction.

Sale of Emera Energy's New England Gas and Bayside Generating Facilities

On March 29, 2019, Emera completed the sale of its three NEGG facilities for cash proceeds of $799 million ($598 million USD), including a working capital adjustment. On March 5, 2019, the Company sold its Bayside facility for cash proceeds of $46 million. The earnings impact of these sale transactions was immaterial. Proceeds from the sales will be used to support capital investment opportunities within Emera's regulated utilities and to reduce corporate debt.

Pending Sale of Emera Maine

On March 25, 2019, Emera announced the sale of Emera Maine for a total enterprise value of approximately $1.3 billion USD including cash proceeds of $959 million USD, transferred debt and a working capital adjustment on close. The transaction is expected to close in late 2019, subject to certain regulatory approvals and provisions of the Hart-Scott Rodino Antitrust Improvements Act. A material gain on the sale is expected to be recognized in earnings at closing. Proceeds from the sale will be used to support capital investment opportunities within Emera's regulated utilities and to reduce corporate debt.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars	
Balance, December 31, 2017	228.77	$	5,601
Conversion of Convertible Debentures	0.01		-
Issuance of common stock	0.45		22
Issued for cash under Purchase Plans at market rate	4.87		200
Discount on shares purchased under Dividend Reinvestment Plan	-		(9)
Options exercised under senior management stock option plan	0.02		1
Employee Share Purchase Plan	-		1
Balance, December 31, 2018	234.12	$	5,816
Issued for cash under Purchase Plans at market rate	1.16		53
Discount on shares purchased under Dividend Reinvestment Plan	-		(2)
Options exercised under senior management stock option plan	0.90		32
Balance, March 31, 2019	**236.18**	**$**	**5,899**

As at May 6, 2019 the amount of issued and outstanding common shares was 237.2 million.

The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended March 31, 2019 was 236.4 million (2018 – 231.0 million).

FINANCIAL HIGHLIGHTS

Florida Electric Utility

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended March 31			
		2019		2018
Operating revenues – regulated electric	**$**	**412**	$	461
Regulated fuel for generation and purchased power		**115**		141
Contribution to consolidated net income	**$**	**46**	$	48
Contribution to consolidated net income – CAD	**$**	**61**	$	60
Contribution to consolidated earnings per common share – basic - CAD	**$**	**0.26**	$	0.26
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.33**	$	1.25
EBITDA	**$**	**166**	$	160
EBITDA – CAD	**$**	**221**	$	202

Net Income

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

For the millions of US dollars	Three months ended March 31
Contribution to consolidated net income – 2018	**$ 48**
Decreased operating revenues - see Operating Revenues - Regulated Electric below	(49)
Decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	26
Decreased OM&G expenses due to Tampa Electric's regulatory agreement to net 2018 tax reform benefits, and storm costs recorded through OM&G in 2018. Beginning in 2019, tax reform benefits are reflected in lower base rates	24
Increased depreciation and amortization due to increased property, plant and equipment	(5)
Increased other income as the result of higher AFUDC earnings due to the construction of solar projects	2
Contribution to consolidated net income – 2019	**$ 46**

Florida Electric Utility's CAD contribution to consolidated net income increased $1 million to $61 million in Q1 2019, compared to $60 million in Q1 2018. Revenues decreased due to a reduction in base rates as a result of tax reform and weather, partially offset by an increase in base rates related to the in-service of solar generation projects. This reduction in revenue was offset by lower OM&G expense in 2019 as the 2018 tax reform benefits were netted against storm costs recorded through OM&G expense in 2018, and the timing of generation outages.

The impact of the change in the foreign exchange rate increased Q1 2019 CAD earnings by $3 million.

Operating Revenues – Regulated Electric

Electric revenues decreased $49 million to $412 million in Q1 2019 compared to $461 million in Q1 2018 primarily due to lower base rates reflecting the impact of US tax reform (beginning January 1, 2019, as approved by the regulator, base rates at Tampa Electric were lowered by $103 million USD annually to reflect the impact of tax reform, resulting in a $22 million USD decrease in revenue in Q1 2019), lower clause recoveries and unfavourable weather. These decreases were partially offset by higher revenues related to in-service of solar generation projects and customer growth.

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

Q1 Electric Revenues
millions of US dollars

	2019	2018
Residential	**$ 206**	$ 230
Commercial	**120**	132
Industrial	**34**	38
Other (1)	**52**	61
Total	**$ 412**	$ 461

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

Q1 Electric Sales Volumes

Gigawatt hours ("GWh")

	2019	2018
Residential	**1,939**	2,021
Commercial	**1,370**	1,404
Industrial	**462**	473
Other	**461**	540
Total	**4,232**	4,438

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power decreased $26 million to $115 million in Q1 2019, compared to $141 million in Q1 2018, due to increased lower-cost natural gas usage, increased lower-cost solar usage and lower production volumes.

Q1 Production Volumes

GWh

	2019	2018
Natural gas	**3,768**	3,445
Coal	**308**	635
Oil and petcoke	**-**	231
Solar	**152**	10
Purchased power	**95**	163
Total	**4,323**	4,484

Q1 Average Fuel Costs

US dollars		2019		2018
Dollars per Megawatt hour ("MWh")	**$**	**27**	$	31

Average fuel cost per MWh decreased in Q1 2019, compared to Q1 2018, primarily due to increased lower-cost natural gas usage and increased lower-cost solar usage.

Canadian Electric Utilities

For the	Three months ended March 31			
millions of Canadian dollars (except per share amounts)		**2019**		2018
Operating revenues – regulated electric	**$**	**443**	$	424
Regulated fuel for generation and purchased power (1)		**192**		175
Income from equity investments		**25**		25
Contribution to consolidated net income	**$**	**96**	$	90
Contribution to consolidated earnings per common share - basic	**$**	**0.41**	$	0.39
EBITDA	**$**	**196**	$	182

(1) Regulated fuel for generation and purchased power includes NSPI's FAM and fixed cost deferrals on the Condensed Consolidated Income Statement, however it is excluded in the segment overview.

Canadian Electric Utilities' contribution is summarized in the following table:

For the millions of Canadian dollars	Three months ended March 31			
		2019		2018
NSPI	**$**	**71**	$	65
Equity investment in NSPML		**14**		15
Equity investment in LIL		**11**		10
Contribution to consolidated net income	**$**	**96**	$	90

Net Income

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

For the millions of Canadian dollars		Three months ended March 31
Contribution to consolidated net income – 2018	**$**	**90**
Increased operating revenues - see Operating Revenues – Regulated Electric below		19
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below		(17)
Decreased FAM and fixed cost deferrals due to current period under recovery of fuel costs partially offset by the higher application of excess non-fuel revenues		4
Decreased OM&G expenses primarily due to lower storm costs		4
Increased depreciation and amortization due to increased property, plant and equipment		(3)
Decreased other expenses, net primarily due to lower non-current service pension costs		4
Increased income tax expense primarily due to increased income before provision for income taxes		(4)
Other		(1)
Contribution to consolidated net income – 2019	**$**	**96**

Canadian Electric Utilities' contribution to consolidated net income increased in Q1 2019 due to a higher contribution from NSPI. This increase was a result of increased sales volume due to weather and decreased OM&G expenses, primarily a result of lower storm costs, partially offset by higher depreciation expense.

NSPI

Operating Revenues – Regulated Electric

Operating revenues increased $19 million to $443 million in Q1 2019 compared to $424 million in Q1 2018. Revenues increased as a result of increased sales volume due to weather and increased fuel related electricity pricing in 2019. This was partially offset by the impact of the Maritime Link assessment.

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

Q1 Electric Revenues
millions of Canadian dollars

		2019		2018
Residential	**$**	**252**	$	236
Commercial		**113**		110
Industrial		**55**		57
Other		**16**		14
Total	**$**	**436**	$	417

Q1 Electric Sales Volumes
GWh

	2019	2018
Residential	**1,621**	1,518
Commercial	**884**	854
Industrial	**597**	624
Other	**143**	115
Total	**3,245**	3,111

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $17 million to $192 million in Q1 2019 compared to $175 million in Q1 2018 primarily due to increased commodity prices, increased sales volumes and due to the payment of the Maritime Link assessment.

Q1 Production Volumes
GWh

	2019	2018
Coal	**1,846**	1,646
Oil and petcoke	**315**	456
Natural gas	**244**	161
Purchased power – other	**141**	88
Total non-renewables	**2,546**	2,351
Wind and hydro	**371**	385
Purchased power – IPP	**370**	386
Purchased power – Community Feed-in Tariff program	**163**	164
Biomass	**15**	40
Total renewables	**919**	975
Total production volumes	**3,465**	3,326

Q1 Average Fuel Costs

	2019	2018
Dollars per MWh	**$ 55**	$ 53

Average fuel cost per MWh increased in Q1 2019, compared to Q1 2018, primarily due to increased commodity pricing and timing of the Maritime Link Assessment, partially offset by a change in generation mix.

NSPI's FAM regulatory liability balance decreased $4 million from $161 million at December 31, 2018 to $157 million at March 31, 2019 primarily due to a refund to customers of the 2018 Maritime Link assessment and under recovery of current period fuel costs. This was partially offset by the recovery of the Maritime Link assessment in 2019 to be returned to customers as part of the assessment decision and an increase in the application of excess non-fuel revenues.

ENL

Income from Equity Investments in NSPML and LIL

Q1 2019 income from equity investments was consistent with Q1 2018. In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI.

Other Electric Utilities

All amounts are reported in USD, unless otherwise stated.

On March 25, 2019, Emera announced the sale of Emera Maine. The transaction is expected to close in late 2019, subject to regulatory approvals. The Company will continue to record depreciation on these assets, through the transaction closing date, as the depreciation continues to be reflected in customer rates, and will be reflected in the carryover basis of the assets when sold. Refer to the "Developments" section for further details.

For the millions of US dollars (except per share amounts)		Three months ended March 31 **2019**		2018
Operating revenues – regulated electric	**$**	**136**	$	137
Regulated fuel for generation and purchased power (1)		**49**		54
Adjusted contribution to consolidated net income	**$**	**12**	$	12
Adjusted contribution to consolidated net income - CAD	**$**	**16**	$	15
After-tax equity securities mark-to-market gain (loss)		**1**		(1)
Contribution to consolidated net income	**$**	**13**	$	11
Contribution to consolidated net income – CAD	**$**	**18**	$	14
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$**	**0.07**	$	0.06
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.08**	$	0.06
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.33**	$	1.26
Adjusted EBITDA	**$**	**47**	$	44
Adjusted EBITDA - CAD	**$**	**62**	$	56

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

Other Electric Utilities' adjusted contribution is summarized in the following table:

For the millions of US dollars		Three months ended March 31		
		2019		2018
Emera Maine	**$**	**8**	$	8
ECI		**4**		4
Adjusted contribution to consolidated net income	**$**	**12**	$	12

Net Income

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

For the millions of US dollars		Three months ended March 31
Contribution to consolidated net income – 2018	**$**	**11**
Operating revenues - see Operating Revenues - Regulated Electric below		(1)
Regulated fuel for generation - see Regulated Fuel for Generation and Purchased Power below		5
Other		(2)
Contribution to consolidated net income – 2019	**$**	**13**

Excluding the change in mark-to-market, Other Electric Utilities CAD contribution to consolidated net income increased by $1 million to $16 million in Q1 2019, compared to $15 million in Q1 2018 due to increased contribution from ECI. ECI's contribution increased primarily due to higher sales volumes at Domlec as a result of the completion of hurricane restoration in 2018 and higher industrial sales volumes at GBPC. The foreign exchange rate had minimal impact for the three months ended March 31, 2019.

Operating Revenues – Regulated Electric

Operating revenues decreased $1 million to $136 million in Q1 2019 compared to $137 million in Q1 2018, primarily due to a decrease in revenue at Emera Maine, partially offset by increased sales volumes at Domlec due to the completion of hurricane restoration in 2018. Emera Maine's revenues decreased due to unfavourable transmission revenue adjustments and lower stranded cost revenue due to the expiration of a major purchased power contract in 2018, partially offset by increased load due to favourable weather and higher distribution and transmission rates in effect in Q1 2019.

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

Q1 Electric Revenues
millions of USD

		2019		2018
Residential	**$**	**51**	$	47
Commercial		**60**		62
Industrial		**9**		9
Other (1)		**16**		19
Total	**$**	**136**	$	137

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

Q1 Electric Sales Volumes

GWh	**2019**	2018
Residential	**339**	328
Commercial	**369**	367
Industrial	**112**	102
Other	**7**	6
Total	**827**	803

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power decreased $5 million to $49 million in Q1 2019, compared to $54 million in Q1 2018 due to the expiration of a major purchased power contract at Emera Maine and lower oil prices at BLPC and GBPC, partially offset by increased volumes at Domlec.

Q1 Production Volumes
GWh

	2019	2018
Oil	**319**	309
Hydro	**4**	4
Solar	**5**	4
Purchased power	**8**	6
Total	**336**	323

(1) Production volumes relate to ECI only.

Q1 Average Fuel Costs

US dollars		**2019**		2018
Dollars per MWh	**$**	**116**	$	124

(2) Average fuel costs relate to ECI only.

Average fuel cost per MWh decreased in Q1 2019, compared to Q1 2018, as a result of lower oil prices.

Gas Utilities and Infrastructure

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)		Three months ended March 31		
		2019		2018
Operating revenues – regulated gas (1)	**$**	**269**	$	269
Operating revenues – non-regulated		**3**		4
Total operating revenue		**272**		273
Regulated cost of natural gas		**103**		110
Income from equity investments		**5**		5
Contribution to consolidated net income	**$**	**51**	$	41
Contribution to consolidated net income – CAD	**$**	**67**	$	53
Contribution to consolidated earnings per common share – basic - CAD	**$**	**0.28**	$	0.23
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.33**	$	1.26
EBITDA	**$**	**102**	$	94
EBITDA – CAD	**$**	**135**	$	119

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2018 – $10 million), however, it is excluded from the gas revenues analysis below.

Gas Utilities and Infrastructure's contribution is summarized in the following table:

For the millions of US dollars		Three months ended March 31		
		2019		2018
PGS	**$**	**18**	$	15
NMGC		**23**		17
Other		**10**		9
Contribution to consolidated net income	**$**	**51**	$	41

Net Income

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

For the millions of US dollars		Three months ended March 31
Contribution to consolidated net income – 2018	**$**	**41**
Gas operating revenues - see Operating Revenues - Regulated Gas below		-
Decreased cost of natural gas sold - see Regulated Cost of Natural Gas below		7
Decreased depreciation and amortization due to accelerated amortization of assets related to manufactured gas plant environmental remediation costs in 2018 at PGS and reduced PGS depreciation rates in 2019 related to the settlement agreement to net amortization of manufactured gas plant environmental regulatory asset and 2018 tax reform benefits		5
Other variances		(2)
Contribution to consolidated net income – 2019	**$**	**51**

Gas Utilities and Infrastructure CAD contribution to consolidated net income increased $14 million to $67 million in Q1 2019 compared to $53 million in Q1 2018. This increase was a result of favourable weather in New Mexico, customer growth in both utilities, lower depreciation and amortization in PGS, and lower OM&G expense in PGS as the 2018 tax reform benefits were recorded through OM&G expense in Q1 2018. These were partially offset by lower revenues in PGS due to tax reform.

The impact of the change in the foreign exchange rate increased Q1 2019 CAD earnings by $3 million compared to Q1 2018.

Operating Revenues – Regulated Gas

Q1 2019 operating revenues were consistent with Q1 2018. Revenues increased due to colder weather in New Mexico and increased customers. This was offset by the impact of lower PGS base rates (beginning January 1, 2019, as approved by the regulator, base rates at PGS were lowered by $12 million USD annually to reflect the impact of tax reform, resulting in a $3 million USD decrease in revenue in Q1 2019), warmer Florida weather and lower commodity costs.

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

Q1 Gas Revenues
millions of US dollars

		2019		2018
Residential	**$**	**142**	$	142
Commercial		**73**		74
Industrial (1)		**9**		9
Other (2)		**34**		34
Total (3)	**$**	**258**	$	259

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $11 million of finance income from Brunswick Pipeline (2018 – $10 million).

Q1 Gas Volumes
Therms (millions)

	2019	2018
Residential	**175**	156
Commercial	**263**	245
Industrial	**337**	317
Other	**61**	50
Total	**836**	768

Regulated Cost of Natural Gas

Regulated cost of natural gas decreased $7 million to $103 million in Q1 2019, compared to $110 million in Q1 2018, due to lower commodity costs in Florida and New Mexico.

Gas sales by type are summarized in the following table:

Q1 Gas Volumes by Type
Therms (millions)

	2019	2018
System supply	**268**	247
Transportation	**568**	521
Total	**836**	768

Other

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2019**	2018
Marketing and trading margin (1) (2)	**$ 54**	$ 69
Electricity and capacity sales (3) (4)	**116**	122
Other non-regulated operating revenue	**10**	10
Total operating revenues – non-regulated	**180**	201
Intercompany revenue (5)	**9**	9
Non-regulated fuel for generation and purchased power (4)(6)	**64**	68
Income from equity investments	**8**	5
Interest expense, net	**93**	89
Adjusted contribution to consolidated net income (loss)	**$ (16)**	$ (16)
After-tax derivative mark-to-market gain	**$ 86**	$ 70
Contribution to consolidated net income	**$ 70**	$ 54
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.07)**	$ (0.07)
Contribution to consolidated earnings per common share – basic	**$ 0.30**	$ 0.23
Adjusted EBITDA	**$ 90**	$ 92

(1) Marketing and trading margin represents EES's purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management services' revenues.
(2) Marketing and trading margin excludes a pre-tax mark-to-market gain of $122 million for the quarter ended March 31, 2019 (2018 - $64 million gain).
(3) Electricity and capacity sales exclude a pre-tax mark-to-market gain of $2 million for the quarter ended March 31, 2019 (2018 - $37 million gain).
(4) On March 29, 2019, Emera completed the sale of the NEGG facilities. Refer to the "Developments" section for further details.
(5) Intercompany revenue consists of interest from Brunswick Pipeline and M&NP.
(6) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market loss of $2 million for the quarter ended March 31, 2019 (2018 - nil gain).

Other's adjusted contribution is summarized in the following table:

For the millions of Canadian dollars	Three months ended March 31 **2019**	2018
Emera Energy	**$ 52**	$ 55
Corporate	**(67)**	(71)
Other	**(1)**	-
Adjusted contribution to consolidated net income (loss)	**$ (16)**	$ (16)

Net Income

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

For the millions of Canadian dollars		Three months ended March 31
Contribution to consolidated net income – 2018	**$**	**54**
Decreased marketing and trading margin - see Emera Energy - Marketing and Trading below		(15)
Decreased electricity and capacity sales net of non-regulated fuel for generation and purchased power - see Emera Energy - Generation below		(2)
Decreased depreciation due to NEGG held for sale classification		9
Increased income from equity investments due to increased capacity prices at Bear Swamp		3
Increased interest expense		(4)
Gain on sale of property in Florida, pre-tax		14
Increased preferred stock dividends due to the issuance of preferred shares in Q2 2018		(4)
Increased mark-to-market gain, net of tax, primarily due to changes in Emera Energy's existing positions on gas contracts and a larger reversal of mark-to-market losses in 2019, partially offset by higher amortization of gas transportation assets in 2019		16
Other		(1)
Contribution to consolidated net income – 2019	**$**	**70**

Excluding the increase in mark-to-market gain, Other's contribution to consolidated net income was consistent quarter-over-quarter, primarily due to the gain on sale of property in Florida offset by the decrease in marketing and trading margin.

Emera Energy

Marketing and Trading

Marketing and trading margin decreased $15 million to $54 million in Q1 2019 compared to $69 million in Q1 2018 due to less favourable market conditions relative to Q1 2018, when the impact of colder weather resulted in higher market prices and volatility that led to higher margins.

Generation

Emera Energy's contribution from generation facilities decreased $2 million to $52 million in Q1 2019, compared to $54 million in Q1 2018. Capacity sales increased $11 million to $38 million in Q1 2019 from $27 million in Q1 2018, due to higher capacity prices that came into effect in New England in June 2018. This was offset by $13 million decrease in energy margin, reflecting less favourable short-term energy hedges, and lower energy sales volumes in New England due to less favourable market conditions in Q1 2019 compared to Q1 2018; and the sale of Bayside Power in Q1 2019.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash from its various regulated and non-regulated energy investments and select asset sales. Utility customer bases are diversified by both sales volumes and 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. Cash flows generated from the sale of select assets are dependent on the market for the assets, acceptable pricing and the timing of the close of any sales. Emera's subsidiaries are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment and maintain their credit metrics.

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

On May 9, 2019, Emera filed a short-form base shelf prospectus, under which the Company may issue common shares in an aggregate principal amount of up to $600 million during the 25 month life of the base shelf prospectus. No common shares have been issued to date under this base shelf prospectus.

At March 31, 2019, Emera had $146 million ($109 million USD) in receivables and other current assets related to the expected refund of alternative minimum tax credit carryforwards. The Company received this refund in April 2019.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the three months ended March 31, 2019 and 2018 include:

millions of Canadian dollars		**2019**		2018		Change
Cash, cash equivalents and restricted cash, beginning of period	**$**	**372**	$	503	$	(131)
Provided by (used in):						
Operating cash flow before change in working capital		**418**		444		(26)
Change in working capital		**(16)**		(11)		(5)
Operating activities		**402**		433		(31)
Investing activities		**298**		(387)		685
Financing activities		**(35)**		(124)		89
Effect of exchange rate changes on cash, cash equivalents and restricted cash		**(5)**		10		(15)
Cash, cash equivalents and restricted cash, end of period	**$**	**1,032**	$	435	$	597

Cash Flow from Operating Activities

Net cash provided by operating activities in Q1 2019 decreased $31 million to $402 million compared to $433 million for the same period in 2018.

Cash from operations before changes in working capital decreased $26 million due to lower marketing and trading margin at Emera Energy, lower margin at Bayside as a result of the sale in early March and various costs which are offset in working capital. These were partially offset by lower pension contributions, the billing of storm costs at Tampa Electric and higher margins at NMGC.

The changes in working capital overall were comparable quarter-over-quarter.

Cash Flow used in Investing Activities

Net cash provided by investing activities increased $685 million to $298 million for the three months ended March 31, 2019 compared to net cash used in financing activities of $387 million for the same period in 2018. In Q1 2019, Emera received proceeds of $861 million on disposition of the NEGG and Bayside facilities, and on sale of property in Florida. These proceeds were partially offset by an increase in capital expenditures.

Capital expenditures for the three months ended March 31, 2019, including AFUDC, were $561 million compared to $349 million for the same period in 2018. Details of the Q1 2019 capital spend by segment are shown below:

- $306 million - Florida Electric Utility (2018 – $161 million);
- $71 million - Canadian Electric Utilities (2018 – $71 million);
- $38 million - Other Electric Utilities (2018 – $30 million);
- $94 million - Gas Utilities and Infrastructure (2018 – $70 million); and
- $52 million - Other (2018 – $17 million).

Cash Flow from Financing Activities

Net cash used in financing activities decreased $89 million to $35 million for the three months ended March 31, 2019 compared to $124 million for the same period in 2018. The decrease was due to increased borrowings under Tampa Electric's credit facilities, partially offset by net repayment of Emera's committed credit facilities.

Contractual Obligations

As at March 31, 2019, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2019	2020	2021	2022	2023	Thereafter	Total
Long-term debt principal (1)	$ 1,096	$ 694	$ 1,708	$ 753	$ 1,160	$ 9,701	$ 15,112
Interest payment obligations (2)(3)	614	639	589	542	518	6,780	9,682
Purchased power (4)(5)	200	206	211	212	215	2,094	3,138
Transportation (6)	429	371	235	196	158	1,388	2,777
Pension and post-retirement obligations (7)(8)	29	34	35	36	36	1,040	1,210
Capital projects (9)	405	144	47	9	3	8	616
Fuel, gas supply and storage	417	133	48	7	3	-	608
Asset retirement obligations	2	27	44	1	1	363	438
Long-term service agreements (10)(11)	35	42	29	26	20	113	265
Equity investment commitments (12)	-	-	190	-	-	-	190
Leases and other (13)	10	8	9	9	8	92	136
Demand side management	31	1	-	-	-	-	32
Long-term payable	3	5	5	5	5	-	23
Convertible debentures	-	-	-	-	-	2	2
	$ 3,271	$ 2,304	$ 3,150	$ 1,796	$ 2,127	$ 21,581	$ 34,229

As noted below, Contractual Obligations at March 31, 2019 include contractual commitments related to Emera Maine. On completion of the sale of Emera Maine, the remaining future obligations related to these contractual commitments will be transferred to the buyer. Refer to the “Developments" section for additional information.

(1) Includes $488 million related to Emera Maine ($40 million in 2020; $120 million in 2022; $47 million in 2023 and $281 million thereafter).

(2) 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 March 31, 2019, including any expected required payment under associated swap agreements.

(3) Includes $358 million related to Emera Maine ($14 million in 2019; $20 million in 2020; $18 million in 2021; $13 million in 2022; $13 million in 2023 and $280 million thereafter).

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

(5) Includes $154 million related to Emera Maine ($8 million in 2019; $11 million in 2020; $11 million in 2021; $11 million in 2022; $11 million in 2023 and $102 million thereafter).

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

(7) Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2018. Credited service and earnings are assumed to be crystallized as at December 31, 2018. The Company's contractual obligations for post-retirement (non-pension) benefits assumes members must be age 55 or over (50 for TECO Energy) as at December 31, 2018 to be eligible. As the defined benefit pension plans currently undergo regular reviews to revise contribution requirements and members are still accruing service under the plans, actual future contributions to the plans will differ from the amounts shown.

(8) Includes $94 million related to Emera Maine ($4 million in 2019; $7 million in 2020; $7 million in 2021; $7 million in 2022; $7 million in 2023 and $62 million thereafter).

(9) Includes $299 million of commitments related to Tampa Electric's solar and Big Bend Power Station modernization projects.

(10) 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.

(11) Includes $38 million related to various long-term service agreements Emera Maine has entered into for IT maintenance and vegetation management ($13 million in 2019; $14 million in 2020; $5 million in 2021; $3 million in 2022; and $3 million in 2023).

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

(13) Includes operating lease agreements for buildings, land, telecommunications services, and rail cars.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years from its January 15, 2018 in-service date. The UARB approved payment for 2019 is $111 million and is subject to a holdback. After 2019, the timing and amounts payable to NSPML will be subject to regulatory filings with the UARB, with expected filings in 2019 and 2020.

Debt Management

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

millions of dollars	Maturity	Revolving Credit Facilities	Utilized	Undrawn and Available
Emera Inc. – Operating and acquisition credit facility	June 2020	$ 900	$ 205	$ 695
TECO Finance, Inc. – in USD – Operating credit facilities	March 2020 - March 2022	900	650	250
NSPI – Operating credit facility	October 2023	600	545	55
TEC - in USD - credit facilities (1)	March 2021 - March 2022	475	313	162
NMGC – in USD – Operating credit facility	March 2022	125	44	81
Emera Maine – in USD – Operating credit facility	February 2023	80	38	42
Other - in USD - Operating credit facility	Various	32	17	15

(1) This facility is available for use by Tampa Electric and PGS. At March 31, 2019, Tampa Electric had utilized $269 million USD and PGS had utilized $44 million USD of the facility.

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements as at March 31, 2019.

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

Canadian Electric Utilities

On April 4, 2019, NSPI completed a $400 million Series AB 30-year medium term notes issuance. The notes bear interest at a rate of 3.57 per cent and have a maturity date of April 5, 2049.

Other

On March 7, 2019, TECO Energy/Finance extended the maturity date of its $500 million USD credit facility from March 8, 2019 to March 5, 2020. There were no other significant changes in commercial terms from the prior agreement.

Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2018 annual MD&A, with updates as noted below:

The Company has standby letters of credit and surety bonds in the amount of $58 million USD (December 31, 2018 - $67 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one year term and are renewed annually as required.

Emera Reinsurance Limited has issued a standby letter of credit to secure obligations under reinsurance agreements. The expiry date of this letter of credit was extended to December 2019. This letter of credit is renewed annually. The amount committed as of March 31, 2019 was $6 million USD (December 31, 2018 - $6 million USD).

TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Intercompany balances and intercompany transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. All material amounts are under normal interest and credit terms.

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

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Condensed Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $27 million for the three months ended March 31, 2019 (2018 - $24 million). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments. Refer to the "Business Overview and Outlook - Canadian Electric Utilities - ENL" and "Contractual Obligations" sections for further details.

- Natural gas transportation capacity purchases from M&NP are reported in the Condensed Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $18 million for the three months ended March 31, 2019 (2018 - $10 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at March 31, 2019 and at December 31, 2018.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

There have been no material changes in Emera's risk management profile and practices from those disclosed in the Company's 2018 annual MD&A.

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	**March 31 2019**	December 31 2018
Derivative instrument liabilities (current and long-term liabilities)	**$ (2)**	$ (5)
Net derivative instrument assets (liabilities)	**$ (2)**	$ (5)

Hedging Impact Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended March 31 **2019**	 2018
Operating revenues – regulated	**$ (2)**	$ 2
Non-regulated fuel for generation and purchased power	**-**	4
Effective net gains (losses)	**$ (2)**	$ 6

The effectiveness 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	**March 31 2019**	December 31 2018
Derivative instrument assets (current and other assets)	**$ 74**	$ 104
Regulatory assets (current and other assets)	**17**	6
Derivative instrument liabilities (current and long-term liabilities)	**(17)**	(6)
Regulatory liabilities (current and long-term liabilities)	**(80)**	(115)
Net asset (liability)	**$ (6)**	$ (11)

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	Three months ended March 31 **2019**	 2018
Regulated fuel for generation and purchased power (1)	**$ 4**	$ 4
Net gains (losses)	**$ 4**	$ 4

(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.

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	**March 31 2019**	December 31 2018
Derivative instrument assets (current and other assets)	**$ 39**	$ 62
Derivative instrument liabilities (current and long-term liabilities)	**(224)**	(354)
Net derivative instrument assets (liabilities)	**$ (185)**	$ (292)

HFT 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	Three months ended March 31 **2019**	 2018
Operating revenues – non-regulated	**$ 149**	$ 128
Non-regulated fuel for generation and purchased power	**(2)**	(2)
Net gains (losses)	**$ 147**	$ 126

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	**March 31 2019**	December 31 2018
Derivative instrument assets (current and other assets)	**$ 14**	$ 1
Net derivative instrument assets (liabilities)	**$ 14**	$ 1

For the three months ended March 31, 2019, the Company had unrealized gains on equity derivatives of $14 million (2018 – nil) recorded in Operating, maintenance and general expense in the Condensed Consolidated Statements of Income.

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 of the Company’s DC&P and ICFR as at March 31, 2019, to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

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

There were no changes in the Company’s ICFR during the quarter ended March 31, 2019 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. There were no material changes in the nature of the Company's critical accounting estimates from those disclosed in the Company's 2018 annual MD&A.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2019, are described as follows:

Leases
On January 1, 2019, the Company adopted Accounting Standard Updates ("ASU") 2016-02, *Leases (Topic 842)*, including all related amendments, using the modified retrospective approach. The standard requires lessees to recognize leases on the balance sheet for all leases with a term of longer than twelve months and disclose key information about leasing arrangements.

As permitted by the optional transition method, Emera did not restate comparative financial information in the Company's condensed consolidated financial statements, did not reassess whether any expired or existing contracts contained leases and carried forward existing lease classifications. Additionally, the Company elected to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under the leasing guidance within ASC Topic 840. The Company elected to use hindsight to determine the lease term for existing leases and elected to not separate lease components from non-lease components for all lessee and lessor arrangements.

Emera has implemented additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. There were no updates to information technology systems as a result of implementation.

The Company's adoption of this new standard resulted in right-of-use ("ROU") assets and lease liabilities of approximately $58 million as of January 1, 2019. The ROU assets and lease liabilities were measured at the present value of remaining lease payments using the Company's incremental borrowing rate.

There was no impact to opening retained earnings as at January 1, 2019 or the Company's net income or cash flows for the three months ended March 31, 2019 as a result of the adoption of the standard. There were no significant impacts to Emera's accounting for lessor arrangements. Refer to note 16 of the financial statements for further detail.

Targeted Improvements to Accounting for Hedging Activities
On January 1, 2019, the Company adopted 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. There was no impact on the condensed consolidated financial statements as a result of the adoption of this standard.

Cloud Computing
In August 2018, the Financial Accounting Standards Board ("FASB") issued ASU 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted and can be applied either retrospectively or prospectively. The Company early adopted the standard effective January 1, 2019 and elected to apply the guidance prospectively. There was no material impact on the condensed consolidated financial statements as a result of the adoption of this standard.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by the FASB. The ASUs that have been issued, but that are not yet effective, are consistent with those disclosed in the Company's 2018 audited consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q1 2019**	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017
Operating revenues	**$ 1,818**	$ 1,799	$ 1,495	$ 1,423	$ 1,807	$ 1,473	$ 1,427	$ 1,469
Net income (loss) attributable to common shareholders	**312**	231	118	90	271	(228)	81	101
Adjusted net income attributable to common shareholders	**224**	167	191	111	202	137	118	117
Earnings per common share - basic	**1.32**	0.98	0.51	0.38	1.17	(1.06)	0.38	0.47
Earnings per common share - diluted	**1.32**	0.98	0.50	0.38	1.17	(1.06)	0.38	0.47
Adjusted earnings per common share - basic	**0.95**	0.71	0.82	0.48	0.87	0.64	0.55	0.55

Quarterly operating revenues and adjusted net income attributable to common shareholders are affected by seasonality. The first quarter provides strong earnings contributions due to a significant portion of the Company's operations being in northeastern North America, where winter is the peak electricity usage season. The third quarter provides strong earnings contributions due to summer being the heaviest electric consumption season in Florida. Seasonal and other weather patterns, as well as the number and severity of storms, can affect the demand for energy and the cost of service. Quarterly results could also be affected by items outlined in the "Significant Items Affecting Earnings" section.