Management’s Discussion & Analysis

As at November 12, 2020

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 third quarter and year-to-date of 2020 relative to the same periods in 2019; and its financial position as at September 30, 2020 relative to December 31, 2019. Throughout this discussion, “Emera Incorporated”, “Emera” and “Company” refer to Emera Incorporated and all of its consolidated subsidiaries and investments. The Company’s activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Other Electric Utilities, Gas Utilities and Infrastructure, and Other.

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 nine months ended September 30, 2020; and the Emera Incorporated annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2019. Emera follows United States Generally Accepted Accounting Principles (“USGAAP” or “GAAP”).

The accounting policies used by Emera’s rate-regulated entities may differ from those used by Emera’s non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. At September 30, 2020, 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”)
Barbados Light & Power Company Limited (“BLPC”)	Fair Trading Commission, Barbados ("FTC")
Grand Bahama Power Company Limited (“GBPC”)	The Grand Bahama Port Authority (“GBPA”)
Dominica Electricity Services Ltd. (“Domlec”)	Independent Regulatory Commission, Dominica (“IRC”)
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”)	Canadian Energy Regulator ("CER")
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”)	CER and FERC

On March 24, 2020, the Company completed the sale of Emera Maine. Refer to the “Significant Items Affecting Earnings” and “Developments” sections for further details.

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”, “budget”, “could”, “estimates”, “expects”, “forecast”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “targets”, “will”, “would” 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; 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; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty 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; uncertainties associated with infectious diseases, pandemics and similar public health threats, such as the COVID-19 novel coronavirus (“COVID-19”) pandemic; 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 service areas have generally experienced stable regulatory policies and economic conditions.

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 $7.4 billion capital investment plan over the 2021-to-2023 period and the potential for additional capital opportunities of $1.2 billion over the same period, resulting in a forecasted rate base growth of 7.5 per cent to 8.5 per cent through to 2023. Management continues to review the timing of capital expenditures in light of the evolving COVID-19 pandemic. This plan includes significant investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. This planned capital investment is being funded primarily through internally generated cash flows and debt raised at the operating company level. Equity requirements in support of the Company's capital investment plan will predominantly be funded in the equity capital markets through the dividend reinvestment plan and the issuance of common and preferred equity. Maintaining investment-grade credit ratings is a priority of management.

Emera has provided annual dividend growth guidance of four to five per cent through to 2022. 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 through and beyond 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 may hedge both transactional and 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 decarbonization. Renewable generation and battery storage are becoming both more affordable and efficient. 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 trends. Emera's strategy is to fund investments in renewable and technology assets which protect the environment and benefit customers through fuel or operating cost savings.

For example, significant investments to facilitate the use of renewable and low-carbon energy include the Maritime Link in Atlantic Canada, the ongoing construction of 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 its customers while keeping rates affordable.

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

NON-GAAP FINANCIAL MEASURES

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

Adjusted Net Income

Emera calculates an adjusted net income measure by excluding the effect of mark-to-market ("MTM") adjustments and impacts in 2020 of the gain on sale of Emera Maine and impairment losses on certain other assets.

The MTM adjustments are a result of the following:

- the mark-to-market adjustments related to Emera's held-for-trading ("HFT") commodity derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered;
- the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp Power Company LLC ("Bear Swamp");
- the amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the mark-to-market adjustments related to an interest rate swap in Brunswick Pipeline;
- the mark-to-market adjustments related to equity securities held in BLPC and Emera Reinsurance, a captive reinsurance company in the Other segment; and
- the mark-to-market adjustments related to Emera's foreign exchange cash flow hedges entered to manage foreign exchange earnings exposure.

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.

In 2020, the Company recognized a gain on the completion of the sale of Emera Maine and impairment losses on certain other assets. Management believes excluding these from net income better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the business. Refer to the "Significant Items Affecting Earnings" and "Developments" sections for further details related to the sale of Emera Maine. While the gain on sale has been excluded from adjusted earnings, earnings for the Other Electric Utilities segment will not include earnings from Emera Maine for the last three quarters of 2020, which were $27 million USD in 2019.

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 September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Net income attributable to common shareholders	**$ 84**	$ 55	**$ 665**	$ 470
Gain on sale and impairment charges, net of tax	**-**	-	**283**	-
After-tax mark-to-market gain (loss)	**(82)**	(67)	**(95)**	(6)
Adjusted net income attributable to common shareholders	**$ 166**	$ 122	**$ 477**	$ 476
Earnings per common share – basic	**$ 0.34**	$ 0.23	**$ 2.70**	$ 1.97
Adjusted earnings per common share – basic	**$ 0.67**	$ 0.51	**$ 1.93**	$ 1.99

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 and amortization adjustments, and the gain on sale and impairment charges, recognized in 2020, as discussed above.

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 September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Net income (1)	**$ 84**	$ 78	**$ 700**	$ 518
Interest expense, net	**163**	183	**520**	557
Income tax expense (recovery)	**(21)**	(49)	**284**	18
Depreciation and amortization	**217**	226	**664**	678
EBITDA	**443**	438	**2,168**	1,771
Gain on sale and impairment charges, excluding income tax	**-**	-	**560**	-
Mark-to-market gain (loss), excluding income tax and interest	**(116)**	(96)	**(136)**	(11)
Adjusted EBITDA	**$ 559**	$ 534	**$ 1,744**	$ 1,782

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

Sale of Emera Maine, Gain on Sale, and Impairment Charges

On March 24, 2020, Emera completed the sale of Emera Maine for a total enterprise value of $2.0 billion ($1.4 billion USD). A gain on sale of $585 million ($309 million after tax, or $1.26 per common share), net of transaction costs, was recognized in "Other Income" on the Condensed Consolidated Statements of Income. Refer to the "Developments" section for further details.

As a result of the sale, earnings contribution from Emera Maine was $16 million lower in Q3 2020 than in Q3 2019 and $32 million lower year-to-date.

In addition, impairment charges of $25 million ($26 million after tax) year-to-date were recognized on certain other assets.

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

After-tax mark-to-market losses increased $15 million to $82 million in Q3 2020, compared to $67 million in Q3 2019. This increase was due to changes in existing positions on gas contracts and higher amortization of gas transportation assets in 2020. Year-to-date, after-tax mark-to-market losses increased $89 million to $95 million in 2020, compared to a $6 million loss in 2019. This increase was due to higher amortization of gas transportation assets in 2020 and a larger reversal of mark-to-market losses in 2019.

Earnings Impact of Q1 2019 Sale of NEGG and Bayside Facilities

Earnings contribution from Emera Energy Generation was $22 million lower year-to-date than in 2019 due to the sale of the New England Gas Generating ("NEGG") and Bayside generation facilities in March 2019.

2019

GBPC Hurricane Dorian Restoration

In Q3 2019, Hurricane Dorian struck Grand Bahama Island as a Category 5 hurricane, causing significant damage across the island. Emera's Q3 2019 earnings decreased by approximately $16 million ($0.07 per common share) compared to Q3 2018 as a result of the impact of the hurricane. GBPC's earnings decreased by $7 million in Q3 2019 compared to Q3 2018 due to reduced load as storm restoration efforts were underway. In addition, Emera recorded a corporate loss of $9 million in Q3 2019, in the Other segment, for the corporate share of the unrecoverable loss on GBPC's facilities.

Consolidated Financial Highlights by Business Segment

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
Adjusted net income	**2020**	2019	**2020**	2019
Florida Electric Utility	**$ 175**	$ 153	**$ 400**	$ 339
Canadian Electric Utilities	**35**	33	**164**	171
Other Electric Utilities	**6**	23	**25**	62
Gas Utilities and Infrastructure	**20**	25	**117**	132
Other	**(70)**	(112)	**(229)**	(228)
Adjusted net income attributable to common shareholders	**$ 166**	$ 122	**$ 477**	$ 476
Gain on sale and impairment charges, net of tax	**-**	-	**283**	-
After-tax mark-to-market gain (loss)	**(82)**	(67)	**(95)**	(6)
Net income attributable to common shareholders	**$ 84**	$ 55	**$ 665**	$ 470

The following table highlights significant changes in adjusted net income attributable to common shareholders from 2019 to 2020.

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Adjusted net income – 2019	**$ 122**	**$ 476**
Increased earnings at Tampa Electric in both periods due to the in-service of solar generation, higher allowance for funds used during construction ("AFUDC") earnings from the Big Bend modernization and solar projects, increased sales to residential customers, favourable weather, customer growth, and a credit to depreciation and amortization expense as a result of a regulatory settlement	22	61
Timing of preferred share dividend declaration	22	11
Recognition of corporate income tax recovery deferred as a regulatory liability in 2018 at BLPC	-	10
2019 recognition of corporate loss for the share of the unrecoverable loss on GBPC's facilities related to Hurricane Dorian	9	9
Increased earnings at Emera Energy Services in Q3 2020 due to lower fixed commitments for gas transportation and storage assets and periods of increased volatility which improved market opportunity. Year-to-date the increase was due to more favourable hedges, partially offset by less favourable winter market conditions in Q1 2020	9	9
Decreased earnings at NSPI due to higher income tax expense and lower commercial sales related to COVID-19 in both periods, the quarter-over-quarter impact of the reversal of fixed cost deferrals in Q3 2019 and unfavourable weather year-to-date. The decrease in both periods was partially offset by increased residential sales related to COVID-19 and decreased operating, maintenance and general ("OM&G") expense	(2)	(13)
Revaluation of Corporate, NSPI and Emera Energy net deferred income tax assets and liabilities due to the Q1 2020 reduction in the Nova Scotia provincial corporate income tax rate	-	(14)
Lower earnings contribution from the Caribbean utilities due to lower sales related to the impact of the COVID-19 pandemic and continued recovery from Hurricane Dorian at GBPC	(1)	(15)
Q3 2019 recognition of tax benefits related to change in treatment of net operating loss ("NOL") carryforwards and tax reform benefits recognized in Q2 2019 in NMGC	(7)	(19)
Decreased earnings due to the sale of Emera Maine in Q1 2020 and the sale of Emera Energy's New England Gas Generating Facilities ("NEGG") and Bayside generation facilities in Q1 2019	(17)	(54)
Other variances	9	16
Adjusted net income – 2020	**$ 166**	**$ 477**

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

For the millions of Canadian dollars	Nine months ended September 30	
	2020	2019
Operating cash flow before changes in working capital	**$ 1,101**	$ 1,182
Change in working capital	**139**	128
Operating cash flow	**$ 1,240**	$ 1,310
Investing cash flow	**$ (536)**	$ (786)
Financing cash flow	**$ (595)**	$ (546)

As at millions of Canadian dollars	**September 30 2020**	December 31 2019
Total assets	**$ 31,918**	$ 31,842
Total long-term debt (including current portion)	**$ 14,085**	$ 14,180

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	Three months ended September 30		Variance	Nine months ended September 30		Variance
	2020	2019		**2020**	2019	
Operating revenues	**$ 1,163**	$ 1,299	$ (136)	**$ 3,969**	$ 4,495	$ (526)
Operating expenses	**990**	1,117	127	**3,186**	3,531	345
Income from operations	**173**	182	(9)	**783**	964	(181)
Income from equity investments	**32**	38	(6)	**113**	118	(5)
Other income (expenses), net	**21**	(8)	29	**608**	11	597
Interest expense, net	**163**	183	20	**520**	557	37
Income tax expense (recovery)	**(21)**	(49)	(28)	**284**	18	(266)
Net income	**84**	78	6	**700**	518	182
Net income attributable to common shareholders	**84**	55	29	**665**	470	195
Gain on sale and impairment charges, net of tax	**-**	-	-	**283**	-	283
After-tax mark-to-market gain (loss)	**(82)**	(67)	(15)	**(95)**	(6)	(89)
Adjusted net income attributable to common shareholders	**$ 166**	$ 122	$ 44	**$ 477**	$ 476	$ 1
Earnings per common share – basic	**$ 0.34**	$ 0.23	$ 0.11	**$ 2.70**	$ 1.97	$ 0.73
Earnings per common share – diluted	**$ 0.34**	$ 0.23	$ 0.11	**$ 2.69**	$ 1.96	$ 0.73
Adjusted earnings per common share – basic	**$ 0.67**	$ 0.51	$ 0.16	**$ 1.93**	$ 1.99	$ (0.06)
Dividends per common share declared	**$ -**	$ 1.2000	$ (1.2000)	**$ 1.8375**	$ 2.3750	$ (0.5375)
Adjusted EBITDA	**$ 559**	$ 534	$ 25	**$ 1,744**	$ 1,782	$ (38)

Operating Revenues

For the third quarter of 2020, operating revenues decreased $136 million compared to the third quarter in 2019. Absent increased mark-to-market losses of $29 million, operating revenues decreased $107 million due to:

- $68 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020;
- $64 million decrease in the Florida Electric Utility segment due to lower clause revenues as a result of a decrease in fuel costs, partially offset by the in-service of solar generation projects, customer growth, a greater mix of residential sales and favourable weather;
- $16 million decrease in the Other Electric Utilities segment due to lower fuel revenue as a result of lower fuel prices, the impact of the COVID-19 pandemic at GBPC and BLPC, and the impact of Hurricane Dorian at GBPC; and
- $12 million decrease in the Gas Utilities and Infrastructure segment as a result of lower clause-related revenues, lower off-system sales and lower commercial sales related to the COVID-19 pandemic at PGS, partially offset by customer growth at PGS.

These impacts were partially offset by increases of:

- $28 million at NSPI in the Canadian Electric Utilities segment due to higher Maritime Link assessment revenue compared to 2019 and higher sales volumes related to the impact of the COVID-19 pandemic on residential customers; and
- $11 million in marketing and trading margin at Emera Energy due to lower fixed commitments for gas transportation and storage assets and increased periods of volatility in Q3 2020, compared to Q3 2019, which improved market opportunity.

Year-to-date in 2020, operating revenues decreased $526 million compared to the same period in 2019. Absent increased mark-to-market losses of $138 million, operating revenues decreased by $388 million due to:

- $147 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020;
- $114 million decrease at Florida Electric Utility due to lower clause revenue, as a result of a decrease in fuel costs, partially offset by the in-service of solar generation projects, a greater mix of residential sales, favourable weather and customer growth;
- $110 million decrease in the Other segment due to the sale of NEGG and Bayside facilities in Q1 2019;
- $66 million decrease in the Gas Utilities and Infrastructure segment as a result of lower clause-related revenues, lower off-system sales at PGS, and NMGC's recognition of tax reform benefits in 2019, partially offset by customer growth at PGS; and
- $41 million decrease in the Other Electric Utilities segment due to lower fuel revenue as a result of lower fuel prices, the impact of COVID-19 pandemic at GBPC and BLPC and the impact of Hurricane Dorian at GBPC.

These impacts were partially offset by an increase of:

- $51 million at NSPI in the Canadian Electric Utilities segment due to higher Maritime Link assessment revenue compared to 2019, increased fuel costs, and higher residential sales volumes, partially offset by decreased commercial, other and industrial sales volumes primarily due to the impact of the COVID-19 pandemic and unfavourable weather.

Operating Expenses

For the third quarter of 2020, operating expenses decreased $127 million compared to the third quarter of 2019. Absent increased mark-to-market gain of $1 million, operating expenses decreased $128 million due to:

- $85 million decrease at Florida Electric Utility due to lower regulated fuel for generation and purchased power as a result of lower natural gas prices and increased use of solar generation;
- $46 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020; and
- $14 million decrease in the Gas Utilities and Infrastructure segment due to lower regulated cost of natural gas reflecting lower commodity costs at PGS and NMGC, and lower volume of commercial and off-system sales at PGS.

These impacts were partially offset by an increase of:

- $20 million at NSPI in the Canadian Electric Utilities segment primarily due to changes in regulatory deferrals, increased fuel for generation and purchased power mainly due to increased commodity prices, partially offset by decreased OM&G expenses.

Year-to-date, operating expenses decreased $345 million compared to the same period of 2019. Absent increased mark-to-market gain of $4 million, operating expenses decreased $349 million due to:

- $171 million decrease at Florida Electric Utility due to lower natural gas prices and increased use of solar generation;
- $99 million decrease in the Other Electric Utilities segment primarily due to the sale of Emera Maine in Q1 2020;
- $80 million decrease in the Other segment as a result of the sale of NEGG in Q1 2019; and
- $51 million decrease in the Gas Utilities and Infrastructure segment due to lower commodity costs at PGS and NMGC, and lower volume of commercial and off-system sales at PGS.

These impacts were partially offset by an increase of:

- $49 million in NSPI in the Canadian Electric Utilities segment primarily due to changes in regulatory deferrals and increased fuel for generation and purchased power due to change in generation mix and increased commodity prices, partially offset by decreased sales volumes and decreased OM&G expenses.

Other Income (Expenses), Net

The increase in other income (expenses), net for the third quarter in 2020 was primarily due to the corporate share of unrecoverable loss at GBPC facilities in 2019 related to Hurricane Dorian and increased AFUDC equity earnings in 2020 primarily related to the Big Bend Modernization and solar projects at Tampa Electric. The increase year-to-date in 2020 was primarily due to the pre-tax gain on sale of Emera Maine, partially offset by impairment charges on certain other assets.

Interest Expense, Net

Interest expense, net was lower for the third quarter and year-to-date compared to 2019 due to lower interest rates and repayment of corporate debt.

Income Tax Expense (Recovery)

The decrease in income tax recovery for the third quarter in 2020, compared to the same period in 2019, was primarily due to increased income before provision for income taxes, decreased deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities, and a change in treatment of NMGC NOL carryforwards in Q3 2019. The increase in income tax expense year-to-date 2020, compared to the same period in 2019, was primarily due to the gain on sale of Emera Maine.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For the third quarter of 2020, net income attributable to common shareholders was unfavourably impacted by the $15 million increase in after-tax mark-to-market losses, primarily related to Emera Energy. Absent the mark-to-market changes, adjusted net income attributable to common shareholders increased $44 million. The increase was due to increased contributions from Florida Electric Utility and Emera Energy Services, timing of preferred stock dividends, and the 2019 Corporate share of the unrecoverable loss at GBPC related to Hurricane Dorian. These were partially offset by lower earnings contribution from Emera Maine as a result of its sale and the 2019 recognition of tax benefits at NMGC.

Year-to-date in 2020, net income attributable to common shareholders was favourably impacted by the $309 million after-tax gain on sale of Emera Maine, and unfavourably impacted by the $89 million increase in after-tax mark-to-market losses primarily related to Emera Energy and after-tax impairment charges. Absent the net gain on sale of Emera Maine, the unfavourable mark-to-market changes and impairment charges, adjusted net income attributable to common shareholders increased $1 million. The increase was due to higher earnings contribution from Florida Electric Utility, timing of preferred share dividends and the 2019 Corporate share of uncoverable loss at GBPC related to Hurricane Dorian. This was partially offset by lower earnings at Emera Maine as a result of its sale in Q1 2020, reduced earnings at NEGG as a result of their sale in Q1 2019, lower earnings contribution from NSPI, revaluation of deferred taxes due to a reduction in the Nova Scotia corporate income tax rate and the 2019 recognition of tax reform benefits in NMGC.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic and adjusted earnings per common share were higher for the third quarter due to increased earnings as discussed above, partially offset by the impact of the increase in the weighted average common shares outstanding.

Earnings per common share – basic was higher year-to-date due to increased earnings as discussed above, partially offset by impact of the increase in the weighted average common shares outstanding. Adjusted earnings per common share – basic was lower year-to-date due to the impact of the increase in the weighted average common shares outstanding.

Effect of Foreign Currency Translation

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

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

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 2020 and 2019 are as follows:

	Three months ended September 30		Nine months ended September 30		Year ended December 31
	2020	2019	**2020**	2019	2019
Weighted average CAD/USD exchange rate	**$ 1.33**	$ 1.32	**$ 1.35**	$ 1.33	$ 1.33
Period end CAD/USD exchange rate	**$ 1.33**	$ 1.32	**$ 1.33**	$ 1.32	$ 1.30

Weakening of the CAD exchange rates increased earnings by $4 million and adjusted earnings by $2 million in Q3 2020 compared to Q3 2019. The weakening of the CAD exchange rates increased earnings by $18 million and adjusted earnings by $6 million year-to-date in 2020, compared to the same period in 2019.

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 foreign currency derivative instruments to hedge specific transactions and earnings exposure. 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 September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Florida Electric Utility	**$ 131**	$ 116	**$ 296**	$ 255
Other Electric Utilities	**5**	18	**19**	47
Gas Utilities and Infrastructure (1)	**8**	12	**67**	82
	144	146	**382**	384
Other segment (2)	**(44)**	(56)	**(107)**	(131)
Total (3)	**$ 100**	$ 90	**$ 275**	$ 253

(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, Bear Swamp and interest expense on Emera Inc.'s US dollar denominated debt and in 2019, net income from NEGG.
(3) Amounts above do not include the impact of mark-to-market.

BUSINESS OVERVIEW AND OUTLOOK

COVID-19 Pandemic

During the three and nine months ended September 30, 2020, the ongoing COVID-19 pandemic has affected all service territories in which Emera operates. Emera's utilities provide essential services and continue to operate and meet customer demand. The Company's top priority continues to be the health and safety of its customers and employees and supporting the communities Emera operates in.

The pandemic has generally resulted in lower load and higher operating costs than what otherwise would have been experienced at the Company's utilities. Some of Emera's utilities have been impacted more than others. However, on a consolidated basis these unfavourable impacts have not had a material financial impact to net earnings to date primarily due to a favourable change to the mix of sales to residential customer classes. Lower commercial and industrial sales have been partially offset by increased sales to residential customers, which have a higher contribution to fixed cost recovery. Favourable weather, in particular in Florida, has further reduced the consolidated impact. The Company has not incurred or deferred for future recovery a significant amount of incremental costs as a result of the pandemic. Capital project delays and supply chain disruptions have been minimal to date. Management continues to closely monitor developments related to COVID-19.

Governments world-wide have implemented measures intended to address the pandemic. These measures include travel and transportation restrictions, quarantines, physical distancing, closures of commercial spaces and industrial facilities, shutdowns, shelter-in-place orders and other health measures. These measures are adversely impacting global, national and local economies. Global equity markets have experienced significant volatility and governments and central banks are implementing measures designed to stabilize economic conditions. The pace and strength of economic recovery is uncertain and may vary among jurisdictions.

In March 2020, Emera activated its company-wide pandemic and business continuity plans, including travel restrictions, directing employees to work remotely whenever possible, restricting access to operating facilities, physical distancing and implementing additional protocols (including the expanded use of personal protective equipment) for work within customers' premises. In jurisdictions where it is safe to do so, some parts of the business have commenced a workplace re-entry strategy. The Company is monitoring recommendations by local and national public health authorities related to COVID-19 and is adjusting operational requirements as needed.

Emera's utilities are working with customers on relief initiatives in response to the effect of the pandemic on customers' ability to pay and their need for continued service. To date, these initiatives have included the temporary suspension of disconnection for non-payment of bills and the development of payment arrangements where necessary. In Q3 2020, most of Emera's utilities resumed disconnection processes for non-payment. As a result of the temporary suspension of disconnections, the Company's utilities experienced an increase in the aging of customer receivables. This trend has begun to reverse as normal disconnection processes resume. To date, there have been no significant customer defaults as a result of bankruptcies with many accounts being secured by deposits. As of September 30, 2020, adjustments to the allowance for credit losses have not had a material impact on earnings. The full impact of potential credit losses due to customer non-payment is not known at this time. The utilities are continuing to monitor customer accounts and are continuing to work with customers on payment arrangements.

The extent of the future impact of COVID-19 on the Company's financial results and business operations cannot be predicted at this time and will depend on future developments, including the duration and severity of the pandemic, further potential government actions and future economic activity and energy usage. In Q1, 2020, the Company updated its principal risks to reflect this uncertainty. Refer to the "Risk Management and Financial Instruments" section and note 21 in the condensed consolidated interim financial statements for this risk update. The Company has disclosed the impact of this uncertainty on its accounting estimates used in the preparation of the financial statements. Refer to the "Critical Accounting Estimates" section, and the "Use of Management Estimates" section of note 1 in the condensed consolidated interim financial statements for further details.

Potential future impacts on the business may include the following:

- Lower earnings as a result of lower sales volumes due to continued economic slowdowns and the pace and strength of economic recovery;
- Delays of capital projects as a result of construction shutdowns, government restrictions on non-essential capital work, travel restrictions for contractors or supply chain disruptions;
- Deferral of and adjustment to regulatory filings, hearings, decisions and recovery periods; and
- Decreased cash flow from operations due to lower earnings and slower collection of accounts receivable or increased credit losses.

To date, the above have not had a material financial impact on the Company. Future impacts on the business will depend on future developments, including the duration and severity of the pandemic and the pace and strength of the economic recovery.

Refer to the outlook sections by segment below for utility-specific impacts. These segment outlooks are based on the information currently available, however, the total impact of COVID-19 is unknown at this time due to uncertainties related to the duration and severity of the pandemic.

Depending on the duration of the COVID-19 pandemic, the forecasted capital expenditures disclosed below may be delayed due to supply chain disruptions, travel restrictions for contractors or the deferral of non-essential capital work, if required. The Company currently expects to continue to have adequate liquidity given its cash position, existing bank facilities, and access to capital, but will continue to monitor the impact of COVID-19 on future cash flows. Refer to the "Liquidity and Capital Resources" section for further details.

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 currently anticipates earning within its allowed ROE range in 2020 and expects rate base to be higher than 2019. An increase in residential sales and favourable weather year-to-date in 2020 have more than offset the impacts of a decrease in other customer classes as a result of COVID-19. In addition, the number of customers increased by 2 per cent in 2020, primarily in the residential class. Expected outcomes and actual results may differ given the many uncertainties related to the pandemic and its economic impact.

On October 3, 2019, the FPSC issued a rule to implement a Storm Protection Plan ("SPP") Cost Recovery Clause. This new clause provides a process for Florida investor-owned utilities, including Tampa Electric, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. Tampa Electric submitted its storm protection plan with the FPSC on April 10, 2020. On April 27, 2020, Tampa Electric submitted a settlement agreement with the FPSC which specified a $15 million USD base rate reduction for SPP program costs previously recovered in base rates beginning January 1, 2021. On June 9, 2020, the FPSC approved this settlement agreement. On August 3, 2020, Tampa Electric submitted another settlement agreement to the FPSC for approval, including cost recovery of approximately $39 million USD in proposed storm protection project costs for 2020 and 2021. This cost recovery includes the $15 million USD of costs removed from base rates. This settlement agreement was approved on August 10, 2020 and Tampa Electric's cost recovery will begin in January 2021. The current approved plan will apply for the years 2020, 2021 and 2022, and Tampa Electric will file a new plan in 2022 to determine cost recovery in 2023, 2024, and 2025.

The June 9, 2020 settlement agreement approved by the FPSC disclosed above also included approval of Tampa Electric's petition to eliminate its $16 million USD accumulated amortization reserve surplus for intangible software assets through a credit to amortization expense in 2020. As stipulated in the settlement, Tampa Electric recognized $4 million USD of this credit in Q3 2020 and $12 million USD year-to-date, with the remaining $4 million USD to be recognized in Q4 2020.

On April 28, 2020, the FPSC approved Tampa Electric's request for a mid-course adjustment to its fuel and capacity charges due to a decline in expected fuel commodity and capacity costs in 2020. The adjustment was effective beginning with June 2020 customer bills resulting in lower fuel and capacity clause rates to customers for the remainder of 2020, and included an acceleration of the return of these savings in the three months starting June 2020.

On February 18, 2020, Tampa Electric announced its intention to invest approximately $800 million USD in an additional 600 MW of new utility-scale solar photovoltaic projects by the end of 2023. Refer to the "Developments" section for further details.

Planned capital expenditures in the Florida Electric Utility segment for 2020 remains at approximately $1.0 billion USD (2019 - $1.1 billion USD), including AFUDC. Capital projects include solar investments, continuation of the modernization of the Big Bend Power Station, storm hardening investments, and advanced metering infrastructure ("AMI").

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 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 energy in both provinces. The Maritime Link will transmit at greater capacity when the Muskrat Falls 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 has resumed its work towards commissioning the LIL after a temporary suspension of work, in March 2020, in response to the COVID-19 pandemic.

NSPI

NSPI anticipates earnings near the low end of its allowed ROE range in 2020. Sales volumes and earnings are expected to be lower than 2019 due to the impact of the COVID-19 pandemic on Nova Scotia's economy and due to unfavourable weather year-to-date. Absent the impact of weather, NSPI has experienced a decrease in sales volumes in the commercial, industrial and other classes, partially offset by an increase in residential sales volumes, which have a higher contribution to fixed cost recovery. NSPI anticipates the overall decrease in sales volumes to continue throughout 2020 depending on the pace of economic recovery. The deferral of capital investment, discussed below, will have a corresponding decreasing effect on NSPI's expected rate base growth in the current year.

NSPI is subject to environmental laws and regulations 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, to maximize efficiency of emission control measures and minimize customer cost. NSPI anticipates that costs prudently incurred to achieve legislated reductions will be recoverable under NSPI's regulatory framework.

In Q1 2020, NSPI received its 2020 granted emissions allowances under the Nova Scotia Cap-and-Trade Program Regulations. These 2020 allowances will be used in 2020 or allocated within the initial four-year compliance period that ends in 2022. Currently, NSPI is on track to meet the requirements of the program. NSPI anticipates that any prudently incurred costs required to comply with the Government of Canada's laws and regulations, and the Nova Scotia Cap-and-Trade Program Regulations, will be recoverable under NSPI's regulatory framework.

Over the past several years, the requirement to reduce Nova Scotia's reliance upon higher carbon and greenhouse gas emitting sources of energy has resulted in NSPI making significant investments in renewable energy sources and purchasing renewable energy from independent power producers. NSPI will have an increase in energy from renewable sources upon delivery of the Nova Scotia block ("NS Block") of electricity transmitted through the Maritime Link from the Muskrat Falls hydroelectric project.

On March 17, 2020, Nalcor announced that it had paused construction activities at the Muskrat Falls site in response to the COVID-19 pandemic. Nalcor resumed work in May 2020 and continues to work toward construction completion and project commissioning in 2021. Refer to the "ENL – Impact of COVID-19 on Muskrat Falls and LIL" section below for further details. Due to the delay of the NS Block, NSPI will not achieve the provincially legislated target of 40 per cent of electric sales generated from renewable sources in 2020. This would have given rise to non-compliance except for the fact that on May 15, 2020, the provincial government provided NSPI with an alternative compliance plan, as permitted by the legislation, which requires NSPI to supply customers with at least 40 per cent of energy generated from renewable sources over the 2020 to 2022 three-year period. NSPI expects to achieve this alternative compliance standard.

As a result of the measures taken to limit the spread of COVID-19, NSPI's forecasted 2020 capital investment was decreased from $375 million pre-COVID-19 to approximately $310 million. The remaining $65 million of capital investments will be deferred to 2021 and 2022. Capital investment in 2019, including AFUDC, was $396 million.

ENL

Equity earnings from NSPML and LIL are expected to be higher in 2020, compared to 2019. 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. NSPML’s approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 30 per cent.

NSPML has UARB approval to collect approximately $145 million (2019 - $111 million) from NSPI for the recovery of costs associated with the Maritime Link in 2020, which is included in NSPI rates. On July 31, 2020, NSPML filed an interim assessment application with the UARB requesting recovery of 2021 costs of approximately $172 million, resulting in an additional $27 million to be collected from NSPI. A decision from the UARB is expected in Q4 2020. NSPML expects to file a final capital cost application for the Maritime Link with the UARB upon commencement of the NS Block of energy from Muskrat Falls.

In 2020, NSPML expects to invest approximately $10 million (2019 - $28 million) in capital.

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 $615 million, comprised of $410 million in equity contribution and $205 million of accumulated equity earnings. Emera’s total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $650 million after all Lower Churchill projects, including Muskrat Falls, are completed.

Cash earnings and return of equity will begin after commissioning of the LIL by Nalcor, and until that point Emera will continue to record AFUDC earnings.

Impact of COVID-19 on Muskrat Falls and LIL

On March 17, 2020, Nalcor announced that it had paused construction activities at the Muskrat Falls site in response to the COVID-19 pandemic. As a result of the effects of COVID-19 on project execution, Nalcor declared force majeure under various project contracts, including formal notification to NSPML. Nalcor resumed work in May 2020. Nalcor achieved first power on the first of four generators at Muskrat Falls on September 22, 2020 and continues to work toward project commissioning in 2021.

Other Electric Utilities

Other Electric Utilities includes:

- 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 51.9 per cent interest in Domlec, a vertically integrated regulated electric utility on the island of Dominica; and
    - a 19.5 per cent interest in Lucelec, a vertically integrated regulated electric utility on the island of St. Lucia.
- Emera Maine, a regulated transmission and distribution electric utility in the state of Maine. On March 24, 2020, Emera completed the sale of Emera Maine. Refer to the “Developments” section for further details.

Removing the impact of the GBPC impairment charge recognized in 2019, Other Electric Utilities' 2020 earnings are expected to decrease over the prior year. This decrease is due to lower earnings contribution from Emera Maine as a result of its sale in March 2020, and lower earnings from the Caribbean utilities primarily related to the COVID-19 pandemic.

Earnings from the Caribbean utilities are expected to be lower in 2020 due to the impact of COVID-19 on local economies which depend heavily on tourism. Tourism and associated support businesses have been significantly impacted by the suspension of international travel. Travel restrictions are gradually being eased but the strength and pace of recovery of the tourism sector is uncertain. As a result, earnings at BLPC and GBPC are expected to be lower than in 2019. The expected decrease in BLPC's earnings will be partially offset by the Q1 2020 recognition of a $6.9 million USD ($10 million CAD) corporate income tax recovery which was deferred as a regulatory liability in 2018. The impact of COVID-19 on GBPC is expected to be partially offset by recovery of load following Hurricane Dorian. GBPC's 2019 earnings were lower than normal as a result of Hurricane Dorian.

On November 6, 2020, BLPC notified the FTC that it plans to file a general rate review application with the FTC in Q1 2021.

On September 1, 2019, Hurricane Dorian struck Grand Bahama Island causing significant damage across the island. In January 2020, the GBPA approved the recovery of approximately $15 million USD of restoration costs related to GBPC's self-insured assets. As of September 30, 2020, $14 million USD of these costs were incurred, and recorded as a regulatory asset. Recovery of the regulatory asset, due to start on April 1, 2020, has been temporarily suspended as a result of the economic impacts of COVID-19 on Grand Bahama. This recovery is now expected to start on January 1, 2021.

In 2020, capital expenditures in the Other Electric Utilities segment are forecasted to be approximately $110 million USD, including $14 million USD invested in Emera Maine projects supporting normal system reliability prior to completion of its sale (2019 – $150 million USD). Completion of BLPC's 33 MW diesel engine installation, expected in mid-2020, was temporarily delayed as a result of government-imposed travel restrictions and is now targeted for 2021.

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.

Earnings from the gas utilities are anticipated to be lower than in 2019 due to impact of the COVID-19 pandemic.

PGS anticipates earning below its allowed ROE range in 2020. Prior to the impact of COVID-19, PGS anticipated it would earn below its allowed ROE range in 2020 primarily due to significant capital investments in support of reliability and overall system growth. In addition, while residential customer growth has been particularly strong in 2020, PGS' overall sales volumes are expected to be lower than in 2019 as a result of the economic impact of COVID-19 in Florida decreasing sales to commercial customers. Beginning mid-March, PGS sales volumes decreased as a result of the impact of government measures and economic conditions on commercial customers and reduced tourism. Therefore, as a result of forecasted revenue requirements being higher than what is in current rates, on June 8, 2020, PGS filed a petition for an increase in rates and service charges effective January 2021.

On October 22, 2020, PGS filed a settlement agreement for approval with the FPSC. The settlement agreement allows for an increase in base rates of $58 million USD annually effective January 2021. The $58 million USD increase includes $24 million USD previously recovered through the cast iron and bare steel replacement rider. The settlement agreement includes an allowed regulatory ROE range of 8.90 per cent to 11.00 per cent with a 9.90 per cent midpoint (2020 - 9.25 per cent to 11.75 per cent with a 10.75 per cent midpoint). The settlement agreement provides PGS with the ability to reverse a total of $34 million USD of accumulated depreciation through 2023 and sets new depreciation rates going into effect January 1, 2021. These depreciation rates are comparatively consistent with PGS' current overall average depreciation rate. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2023, unless its earned ROE falls below 8.90 per cent before that time, with an allowed equity capital structure of 54.7 per cent. The settlement agreement further addresses tax rate changes. PGS will quantify the future impact of decreases in tax rates on net operating income through a reduction in base revenues within 120 days of when such tax change becomes law. If tax legislation results in a tax rate increase, PGS can establish a regulatory asset to neutralize the impact of the increase in income tax rate to be addressed in PGS' next base rate proceeding. A decision from the FPSC is expected in 2020.

NMGC anticipates earning near its allowed ROE in 2020 and expects rate base to be higher than 2019. Assuming normal weather, NMGC sales volumes are expected to decrease, as 2019 energy sales benefited from favourable weather in the first half of 2019. NMGC sales volumes to date have not been significantly impacted by COVID-19. Depending on the duration of COVID-19 related restrictions, industrial and commercial sales volumes are expected to decrease. Earnings from NMGC are also expected to be lower as a result of the 2019 recognition of tax reform benefits, and the approved change in treatment of NOL carryforwards in 2019, which contributed a total of $14 million USD to earnings last year.

On December 23, 2019, NMGC filed a future year rate case for new rates effective January 2021. On August 25, 2020, NMGC filed a settlement agreement with the NMPRC and, on October 20, 2020, a hearing in front of the Hearing Examiner was held. The proposed new rates reflect the recovery of capital investment in pipelines and related infrastructure and would be expected to result in an increase in revenue of approximately $5 million USD annually. A decision from the NMPRC is expected in 2020.

In 2020, capital expenditures in the Gas Utilities and Infrastructure segment are expected to be approximately $600 million USD (2019 - $331 million USD), including AFUDC. PGS will make investments to expand its system and support customer growth. NMGC will complete the Santa Fe Mainline Looping project in 2020 and will continue to invest in system improvements. SeaCoast will continue to invest in the Seminole Pipeline and the Callahan Pipeline with approximately $90 million USD expected to be invested in 2020. The Seminole and Callahan Pipelines remain on schedule with total costs of approximately $100 million USD and $30 million USD, respectively.

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;
- Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; 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.

In 2019, the Company completed the sale of assets previously reported in this segment including the sale of its NEGG and Bayside facilities in March 2019 and the sale of its Emera Utility Services equipment and inventory in December 2019. These operations contributed $20 million to earnings in 2019.

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, corporate human resources activities, acquisition and disposition related costs, gains or losses on select assets sales, and gains or losses on foreign exchange cash flow hedges entered to manage foreign exchange earnings exposure. 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 annual 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. While the COVID-19 related economic slowdown has not had a material impact on EES earnings to date, the business continues to experience a challenging market environment of low absolute natural gas pricing and volatility in its core geographies. Assuming that continues to be the case in Q4 2020, EES expects to outperform 2019, but could fall short of the low end of its normal range for 2020.

The Other segment is expected to contribute positively to earnings in 2020 due to the gain on sale of Emera Maine recognized in earnings. Absent this gain and impairment losses recognized in 2020, the adjusted net loss from the Other segment is expected to be consistent with the prior year. This is primarily due to lower interest expense and increased EES contribution being offset by decreased tax recoveries and lower earnings contribution due to the sale of NEGG in 2019. The decrease in tax recoveries is due to the revaluation of net deferred income tax assets at the lower Nova Scotia corporate income tax rate enacted in March 2020.

In 2020, capital expenditures in the Other segment are expected to be approximately $25 million (2019 - $63 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Condensed Consolidated Balance Sheets between December 31, 2019 and September 30, 2020 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**$ 64**	Increased due to proceeds on the sale of Emera Maine and cash from operations. This was partially offset by additions of property, plant and equipment, net repayment of debt at TECO Finance, net repayment of Emera committed credit facilities and dividends on common stock.
Receivables and other assets (current and long-term)	**(132)**	Decreased due to seasonality of the business at NSPI and NMGC, lower gas transportation assets at Emera Energy, lower commodity prices and volumes at Emera Energy and a refund of prior year income taxes receivable at NSPI. This was partially offset by the reclassification of corporate alternative minimum tax carryforwards from deferred income tax liabilities, higher revenues and increased aging of receivables due to the temporary suspension of disconnections for non-payment of bills at Tampa Electric and the effect of a weaker CAD on the translation of Emera's foreign affiliate.
Assets held for sale (current and long-term), net of liabilities	**(691)**	Decreased due to the sale of Emera Maine.
Property, plant and equipment, net of accumulated depreciation and amortization	**1,597**	Increased due to additions at Tampa Electric, PGS and NSPI and the effect of a weaker CAD on the translation of Emera's foreign affiliates.
Goodwill	**158**	Increased due to the effect of a weaker CAD on the translation of Emera's foreign affiliates.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**(87)**	Decreased due to net repayments on committed credit facilities at TECO Finance and Emera, and net repayment of long-term debt at TECO Finance. This was partially offset by a net issuance on committed credit facilities at Tampa Electric and the effect of a weaker CAD on the translation of Emera's foreign affiliates.
Deferred income tax liabilities, net of deferred income tax assets	**302**	Increased due to net utilization of tax loss carryforwards primarily related to the sale of Emera Maine, tax deductions in excess of accounting depreciation related to property, plant and equipment and the effect of a weaker CAD on the translation of Emera's foreign subsidiaries. The increase was partially offset by the revaluation of net deferred income tax liabilities resulting from enactment of a lower Nova Scotia provincial corporate income tax rate in Q1 2020.
Derivative instruments (current and long-term)	**66**	Increased due to new contracts at Emera Energy, partially offset by the reversal of 2019 contracts at Emera Energy and the settlement of contracts at NSPI.
Regulatory liabilities (current and long-term)	**(59)**	Decreased due to changes in the fuel adjustment mechanism deferral and derivative instrument deferrals at NSPI and decreased deferred income tax regulatory liabilities primarily due to increased amortization of excess deferred income taxes related to US Tax Reform at Tampa Electric, PGS and NMGC. This was partially offset by the effect of a weaker CAD on the translation of Emera's foreign affiliates.

Other liabilities (current and long-term)	**163**	Increased due to investment tax credits related to solar projects at Tampa Electric, timing of interest payments on corporate debt and the effect of a weaker CAD on the translation of Emera's foreign affiliates.
Common stock	**325**	Increased due to shares issued under Emera's at-the-market equity plan, the dividend reinvestment plan and stock options exercised.
Accumulated other comprehensive income	**168**	Increased due to the effect of a weaker CAD on the translation of Emera's foreign affiliates.
Retained earnings	**209**	Increased due to the gain on sale of Emera Maine, offset by dividends paid in excess of net income.

DEVELOPMENTS

Increase in Common Dividend

On September 16, 2020, Emera’s Board of Directors approved an increase in the annual common share dividend rate to $2.55 from $2.45. The first payment will be effective November 16, 2020. Emera also reaffirmed its four to five per cent annual dividend growth rate target through to 2022.

Sale of Emera Maine

On March 24, 2020, Emera completed the sale of Emera Maine for a total enterprise value of $2.0 billion ($1.4 billion USD), including cash proceeds of $1.4 billion, transferred debt and a working capital adjustment. A gain on sale of $309 million after tax, net of transaction costs, was recognized in the Other segment. Proceeds from the sale are being used to support capital investment opportunities within Emera’s regulated utilities and to reduce corporate debt.

Tampa Electric Solar Investment

On February 18, 2020, Tampa Electric announced its intention to invest approximately $800 million USD in an additional 600 MW of new utility-scale solar photovoltaic projects by the end of 2023. On completion of these projects, approximately 22 per cent or 1,250 MW of Tampa Electric’s total generating capacity will be solar.

Appointments

Executive

Effective October 14, 2020, Peter Gregg was appointed President and CEO of NSPI. Most recently, Mr. Gregg was the President and CEO of the Independent Electricity System Operator in Ontario. Mr. Gregg succeeded Richard Janega, who was appointed interim President and CEO of NSPI effective June 1, 2020. Mr. Janega is Emera’s Chief Operating Officer, Electric Utilities, Canada, US Northeast and Caribbean.

OUTSTANDING STOCK DATA

Common stock

Issued and outstanding:	millions of shares	millions of Canadian dollars	
Balance, December 31, 2018	234.12	$	5,816
Conversion of Convertible Debentures	0.03		1
Issuance of common stock (1)	1.77		99
Issued for cash under Purchase Plans at market rate	3.99		202
Discount on shares purchased under Dividend Reinvestment Plan	-		(7)
Options exercised under senior management stock option plan	2.57		104
Employee Share Purchase Plan	-		1
Balance, December 31, 2019	242.48	$	6,216
Issuance of common stock (2)	2.71		151
Issued for cash under Purchase Plans at market rate	2.82		155
Discount on shares purchased under Dividend Reinvestment Plan	-		(3)
Options exercised under senior management stock option plan	0.42		20
Employee Share Purchase Plan	-		2
Balance, September 30, 2020	**248.43**	**$**	**6,541**

(1) In Q3 2019 and in the nine months ended September 30, 2019, 880,912 common shares were issued under Emera's at-the-market program ("ATM program") at an average price of $56.76 per share for gross proceeds of $50 million ($49 million net of issuance costs).
(2) In Q3 2020, 980,500 common shares were issued under Emera's ATM program at an average price of $54.43 per share for gross proceeds of $53 million ($53 million net of issuance costs). During the nine months ended September 30, 2020, 2,708,603 common shares were issued under Emera's ATM program at an average price of $56.62 per share for gross proceeds of $153 million ($151 million net of issuance costs). As at September 30, 2020, an aggregate gross sales limit of $347 million remains available for issuance under the ATM program.

As the Q3 2020 dividends were declared by the Board of Directors and recognized in Q2 2020, there were no common or preferred share dividends recognized in Q3 2020.

As at November 9, 2020, the amount of issued and outstanding common shares was 249.4 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 September 30, 2020 was 248.4 million (2019 – 241.0 million) and for the nine months ended September 30, 2020 was 246.6 million (2019 – 238.9 million).

Cumulative Preferred Stock

For details regarding cumulative preferred stock, refer to note 27 in Emera’s 2019 annual audited financial statements, with updates as noted below:

On July 9, 2020, Emera announced it would not redeem the Cumulative Rate Reset Preferred Shares, Series A (“Series A Shares”) or the Cumulative Floating Rate First Preferred Shares, Series B (“Series B Shares”). On August 17, 2020, Emera announced 128,610 of its 3,864,636 issued and outstanding Series A Shares were tendered for conversion into Series B Shares and 1,130,788 of its 2,135,364 issued and outstanding Series B Shares were tendered for conversion into Series A Shares, all on a one-for-one basis. As a result of the conversion, Emera has 4,866,814 Series A Shares and 1,133,186 Series B Shares issued and outstanding.

On July 16, 2020, Emera announced a dividend rate of 2.182 per cent per annum on the Series A Shares during the five-year period which commenced on August 15, 2020 and ends on (and inclusive of) August 14, 2025 ($0.1364 per Series A Share per quarter). Emera also announced a dividend rate of 2.021 per cent on the Series B Shares for the three-month period which commenced on August 15, 2020 and ends on (and inclusive of) November 14, 2020 ($0.1274 per Series B Share for the quarter).

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 September 30				Nine months ended September 30		
		2020		2019		**2020**		2019
Operating revenues – regulated electric	**$**	**506**	$	559	**$**	**1,381**	$	1,492
Regulated fuel for generation and purchased power		**102**		168		**301**		439
Contribution to consolidated net income	**$**	**131**	$	116	**$**	**296**	$	255
Contribution to consolidated net income – CAD	**$**	**175**	$	153	**$**	**400**	$	339
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.70**	$	0.63	**$**	**1.62**	$	1.42
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.33**	$	1.32	**$**	**1.35**	$	1.33
EBITDA	**$**	**270**	$	249	**$**	**690**	$	641
EBITDA – CAD	**$**	**359**	$	331	**$**	**933**	$	853

Net Income

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

For the millions of US dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2019	**$**	**116**	**$**	**255**
Decreased operating revenues - see Operating Revenues - Regulated Electric below		(53)		(111)
Decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below		66		138
Increased depreciation and amortization due to increased property, plant and equipment partially offset by a $4 million in Q3 2020 ($12 million year-to-date) credit to amortization expense recognized for Tampa Electric's accumulated amortization reserve surplus for intangible software assets		(2)		(3)
Increased other income as a result of higher AFUDC earnings due to the Big Bend Power Station modernization and solar projects		4		10
Other		-		7
Contribution to consolidated net income – 2020	**$**	**131**	**$**	**296**

Florida Electric Utility’s CAD contribution to consolidated net income increased $22 million in Q3 2020, compared to Q3 2019. Year-to-date, the CAD contribution to consolidated net income increased $61 million in 2020 compared to the same period in 2019. The increase in both periods was due to increased base revenues and higher AFUDC earnings as a result of the Big Bend modernization and solar projects. Operating revenues decreased due to lower clause revenues; however, base revenues increased as a result of the in-service of solar generation projects, a greater mix of residential sales, favourable weather and customer growth.

The impact of the change in the foreign exchange rate increased CAD earnings for the three and nine months ended September 30, 2020 by $1 million and $7 million, respectively.

Operating Revenues – Regulated Electric

Electric revenues decreased $53 million to $506 million in Q3 2020, compared to $559 million in Q3 2019 due to lower clause revenues as a result of a decrease in fuel cost, partially offset by the in-service of solar generation projects, customer growth, a greater mix of residential sales and favourable weather.

Year-to-date, electric revenues decreased $111 million to $1,381 million in 2020, compared to $1,492 million for the same period in 2019 due to lower clause revenues as a result of a decrease in fuel cost. The year-to-date decrease in revenues was partially offset by increased base revenues from in-service of solar generation projects, a greater mix of residential sales, favourable weather and customer growth.

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

Q3 Electric Revenues
millions of US dollars

		2020		2019
Residential	**$**	**303**	$	325
Commercial		**128**		160
Industrial		**30**		41
Other (1)		**45**		33
Total	**$**	**506**	$	559

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

YTD Electric Revenues
millions of US dollars

		2020		2019
Residential	**$**	**762**	$	792
Commercial		**374**		421
Industrial		**99**		117
Other (1)		**146**		162
Total	**$**	**1,381**	$	1,492

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

Q3 Electric Sales Volumes (1)
Gigawatt hours ("GWh")

	2020	2019
Residential	**3,259**	2,976
Commercial	**1,728**	1,791
Industrial	**482**	519
Other	**527**	548
Total	**5,996**	5,834

(1) Electric sales volumes are calculated based on billed hours only. GWh related to unbilled revenues are excluded.

YTD Electric Sales Volumes (1)
GWh

	2020	2019
Residential	**7,657**	7,281
Commercial	**4,532**	4,704
Industrial	**1,431**	1,520
Other	**1,443**	1,515
Total	**15,063**	15,020

(1) Electric sales volumes are calculated based on billed hours only. GWh related to unbilled revenues are excluded.

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power decreased $66 million to $102 million in Q3 2020, compared to $168 million in Q3 2019. Year-to-date, regulated fuel for generation and purchased power decreased $138 million to $301 million in 2020, compared to $439 million in the same period in 2019. The decrease in both periods was due to lower natural gas prices and increased use of zero fuel cost solar generation.

Q3 Production Volumes
GWh

	2020	2019
Natural gas	**4,652**	5,006
Coal	**301**	219
Solar	**304**	210
Purchased power	**910**	657
Total	**6,167**	6,092

YTD Production Volumes
GWh

	2020	2019
Natural gas	**12,907**	13,439
Coal	**560**	891
Solar	**888**	587
Purchased power	**1,766**	1,080
Total	**16,121**	15,997

Q3 Average Fuel Costs

US dollars	**2020**	2019
Dollars per Megawatt hour ("MWh")	**$ 17**	$ 28

YTD Average Fuel Costs

US dollars	**2020**	2019
Dollars per MWh	**$ 19**	$ 27

Average fuel cost per MWh decreased in Q3 2020 and year-to-date, compared to the same periods in 2019, primarily due to increased use of lower-cost natural gas and zero fuel cost solar generation.

Canadian Electric Utilities

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Operating revenues – regulated electric	**$ 324**	$ 296	**$ 1,117**	$ 1,066
Regulated fuel for generation and purchased power (1)	**162**	147	**502**	480
Income from equity investments	**24**	20	**75**	68
Contribution to consolidated net income	**$ 35**	$ 33	**$ 164**	$ 171
Contribution to consolidated earnings per common share – basic	**$ 0.14**	$ 0.14	**$ 0.67**	$ 0.72
EBITDA	**$ 130**	$ 117	**$ 457**	$ 441

(1) Regulated fuel for generation and purchased power includes NSPI's Fuel Adjustment Mechanism ("FAM") and fixed cost deferrals on the Condensed Consolidated Statements of Income; 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 September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
NSPI	**$ 11**	$ 13	**$ 89**	$ 103
Equity investment in NSPML	**11**	9	**38**	35
Equity investment in LIL	**13**	11	**37**	33
Contribution to consolidated net income	**$ 35**	$ 33	**$ 164**	$ 171

Net Income

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

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2019	**$**	**33**	**$**	**171**
Increased operating revenues - see Operating Revenues – Regulated Electric below		28		51
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below		(15)		(22)
Increased primarily due to a reversal of fixed cost deferrals in 2019 and increased FAM expense. Year-over-year decrease due to the refund to customers of prior years' over-recovery of fuel costs, partially offset by the over-recovery of current period fuel costs		(28)		(40)
Decreased OM&G expense quarter-over-quarter primarily due to lower storm restoration costs, and lower costs for power generation and vegetation management. These decreases were partially offset by lower administrative overhead allocated to property, plant and equipment, COVID-19 pandemic response costs and decreased demand side management ("DSM") program costs due to lower program costs. Year-over-year this decrease was also offset by higher information technology costs		23		17
Increased income from equity investments due to timing of OM&G expenses at NSPML and increased AFUDC earnings from LIL		4		6
Increased income taxes primarily due to lower tax deductions in excess of accounting depreciation related to property, plant and equipment		(11)		(22)
Other		1		3
Contribution to consolidated net income – 2020	**$**	**35**	**$**	**164**

Canadian Electric Utilities' contribution to consolidated net income increased in Q3 2020, compared to Q3 2019, due to decreased OM&G expense, higher residential electric sales at NSPI and higher equity earnings at ENL, partially offset by lower recoveries of regulatory deferrals, reversal of fixed cost deferral in 2019 and increased income taxes resulting from lower tax deductions in excess of accounting depreciation related to property, plant and equipment.

Year-to-date, the decrease in contribution to consolidated net income was due to the unfavourable impacts of increased income tax expense, as discussed above, weather and decreased commercial, other and industrial sales volumes related to the impact of the COVID-19 pandemic, partially offset by decreased OM&G expense and increased residential sales volumes related to the impact of the COVID-19 pandemic at NSPI and higher equity earnings at ENL.

NSPI

Operating Revenues – Regulated Electric

Operating revenues increased $28 million to $324 million in Q3 2020, compared to $296 million in Q3 2019 due to a higher Maritime Link assessment included in revenue compared to 2019, increased residential sales volumes related to the impact of the COVID-19 pandemic and increased fuel-related pricing. This was partially offset by decreased commercial sales volumes primarily due to the impact of the COVID-19 pandemic. Year-to-date, operating revenues increased $51 million to $1,117 million compared to $1,066 million for the same period in 2019 due to a higher Maritime Link assessment included in revenue compared to 2019, increased fuel-related pricing, and higher residential sales volumes, partially offset by decreased commercial, other and industrial sales volumes primarily due to the impact of the COVID-19 pandemic and unfavourable weather.

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

Q3 Electric Revenues
millions of Canadian dollars

	2020	2019
Residential	**$ 161**	$ 135
Commercial	**93**	91
Industrial	**57**	52
Other	**7**	11
Total	**$ 318**	$ 289

YTD Electric Revenues
millions of Canadian dollars

	2020	2019
Residential	**$ 607**	$ 552
Commercial	**303**	298
Industrial	**164**	160
Other	**24**	35
Total	**$ 1,098**	$ 1,045

Q3 Electric Sales Volumes
GWh

	2020	2019
Residential	**898**	810
Commercial	**657**	707
Industrial	**614**	629
Other	**37**	72
Total	**2,206**	2,218

YTD Electric Sales Volumes
GWh

	2020	2019
Residential	**3,493**	3,454
Commercial	**2,138**	2,305
Industrial	**1,712**	1,817
Other	**149**	272
Total	**7,492**	7,848

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $15 million to $162 million in Q3 2020 compared to $147 million in Q3 2019. Year-to-date, regulated fuel for generation and purchased power increased $22 million to $502 million compared to $480 million in the same period in 2019. The increase was primarily due to increased commodity prices and a change in generation mix, partially offset by decreased sales volumes.

Q3 Production Volumes
GWh

	2020	2019
Coal	**949**	918
Natural gas	**495**	451
Oil and petcoke	**247**	204
Purchased power – other	**114**	277
Total non-renewables	**1,805**	1,850
Purchased power – Independent Power Producers ("IPP")	**253**	195
Wind and hydro	**126**	202
Purchased power – Community Feed-in Tariff program ("COMFIT")	**109**	96
Biomass	**44**	14
Total renewables	**532**	507
Total production volumes	**2,337**	2,357

YTD Production Volumes
GWh

	2020	2019
Coal	**3,093**	3,551
Natural gas	**1,521**	1,047
Oil and petcoke	**793**	832
Purchased power – other	**428**	647
Total non-renewables	**5,835**	6,077
Purchased power – IPP	**897**	831
Wind and hydro	**786**	983
Purchased power – COMFIT	**402**	389
Biomass	**85**	59
Total renewables	**2,170**	2,262
Total production volumes	**8,005**	8,339

Q3 Average Fuel Costs

	2020	2019
Dollars per MWh	**69**	62

YTD Average Fuel Costs

	2020	2019
Dollars per MWh	**63**	58

Average fuel cost per MWh increased in Q3 2020 and year-to-date, compared to the same periods in 2019 primarily due to increased commodity pricing and a change in generation mix resulting from higher natural gas consumption and lower generation from NSPI-owned hydro and wind, which have no fuel cost component. This was partially offset by lower generation from solid fuel and a decrease in purchased power.

NSPI’s FAM regulatory liability balance decreased $33 million from $115 million at December 31, 2019 to $82 million at September 30, 2020 primarily due to the refund of prior years’ over-recovery of fuel costs and reduced Maritime Link assessment to customers. This was partially offset by over-recovery of current-period fuel costs.

Other Electric Utilities

All amounts are reported in USD, unless otherwise stated.

On March 24, 2020, Emera completed the sale of Emera Maine. Refer to the “Significant Items Affecting Earnings” and “Developments” sections for further details.

For the millions of US dollars (except per share amounts)	Three months ended September 30 **2020**	2019	Nine months ended September 30 **2020**	2019
Operating revenues – regulated electric	**$ 79**	$ 144	**$ 275**	$ 421
Regulated fuel for generation and purchased power (1)	**33**	55	**110**	158
Adjusted contribution to consolidated net income	**$ 5**	$ 18	**$ 19**	$ 47
Adjusted contribution to consolidated net income – CAD	**$ 6**	$ 23	**$ 25**	$ 62
After-tax equity securities mark-to-market gain (loss)	**-**	-	**-**	2
Contribution to consolidated net income	**$ 5**	$ 18	**$ 19**	$ 49
Contribution to consolidated net income – CAD	**$ 6**	$ 23	**$ 25**	$ 64
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$ 0.02**	$ 0.10	**$ 0.10**	$ 0.26
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.02**	$ 0.10	**$ 0.10**	$ 0.27
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.33**	$ 1.33	**$ 1.36**	$ 1.33
Adjusted EBITDA	**$ 21**	$ 52	**$ 77**	$ 149
Adjusted EBITDA – CAD	**$ 26**	$ 67	**$ 102**	$ 197

(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 September 30 **2020**	2019	Nine months ended September 30 **2020**	2019
Emera Maine	**$ -**	$ 11	**$ 4**	$ 28
ECI	**5**	7	**15**	19
Adjusted contribution to consolidated net income	**$ 5**	$ 18	**$ 19**	$ 47

Net Income

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

For the millions of US dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2019	**$**	**18**	**$**	**49**
Decreased operating revenues - see Operating Revenues - Regulated Electric below		(13)		(36)
Regulated fuel for generation - see Regulated Fuel for Generation and Purchased Power below		12		28
Increased income tax recovery primarily due to recognition of a previously deferred corporate income tax recovery in Q1 2020 related to enactment of a lower corporate income tax rate in December 2018 at BLPC		-		7
Impact of sale of Emera Maine, net of tax		(11)		(24)
Other		(1)		(5)
Contribution to consolidated net income – 2020	**$**	**5**	**$**	**19**

Excluding the change in mark-to-market, Other Electric Utilities CAD contribution to consolidated net income decreased $17 million in Q3 2020, compared to Q3 2019. Year-to-date, the CAD contribution decreased $37 million in 2020 compared to the same period in 2019. Lower contribution from Emera Maine as a result of its sale in Q1 2020 decreased earnings in both periods. ECI's year-to-date contribution decreased due to lower commercial and industrial sales, partially offset by increased sales to residential customers due to the impact of the COVID-19 pandemic and due to the continued recovery from Hurricane Dorian at GBPC. Year-to-date, the decrease was partially offset by recognition of a previously deferred corporate income tax recovery related to enactment of a lower corporate income tax rate in December 2018 at BLPC.

The foreign exchange rate had minimal impact for the three months ended September 30 and year-to-date 2020.

Operating Revenues – Regulated Electric

Operating revenues decreased $65 million to $79 million in Q3 2020, compared to $144 million in Q3 2019. Year-to-date revenues decreased $146 million to $275 million compared to $421 million in the same period in 2019. Decreases in both periods were a result of the sale of Emera Maine in Q1 2020, lower fuel revenue at BLPC as a result of lower fuel prices, lower commercial and industrial sales partially offset by increased sales to residential customers due to the impact of the COVID-19 pandemic in the Caribbean, and the continued recovery from the impact of Hurricane Dorian at GBPC. GBPC's revenue in Q3 2020 was slightly higher than in Q3 2019; however, Q3 2019 revenues were low due to the impact of Hurricane Dorian in September 2019.

Electric revenues and sales volumes for ECI's utilities are summarized in the following tables by customer class:

Q3 Electric Revenues
millions of USD

		2020		2019
Residential	**$**	**31**	$	33
Commercial		**40**		50
Industrial		**5**		4
Other		**3**		5
Total	**$**	**79**	$	92

YTD Electric Revenues
millions of USD

		2020		2019
Residential	**$**	**84**	$	90
Commercial		**121**		149
Industrial		**16**		15
Other		**10**		12
Total	**$**	**231**	$	266

Q3 Electric Sales Volumes		
GWh	**2020**	2019
Residential	**137**	122
Commercial	**164**	188
Industrial	**19**	16
Other	**6**	3
Total	**326**	329

YTD Electric Sales Volumes		
GWh	**2020**	2019
Residential	**369**	347
Commercial	**481**	554
Industrial	**61**	59
Other	**16**	11
Total	**927**	971

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power decreased $22 million to $33 million in Q3 2020, compared to $55 million in Q3 2019. Year-to-date, regulated fuel for generation and purchased power decreased $48 million to $110 million compared to $158 million in the same period in 2019. The decreases in both periods were as a result of the sale of Emera Maine in Q1 2020 and lower fuel costs at BLPC.

Production volumes and average fuel costs for ECI's utilities are summarized in the following tables:

Q3 Production Volumes GWh		
	2020	2019
Oil	**331**	344
Hydro	**4**	5
Solar	**5**	5
Purchased power	**15**	9
Total	**355**	363

YTD Production Volumes GWh		
	2020	2019
Oil	**933**	1,006
Hydro	**12**	15
Solar	**13**	14
Purchased power	**40**	25
Total	**998**	1,060

Q3 Average Fuel Costs		
US dollars	**2020**	2019
Dollars per MWh	**92**	124

YTD Average Fuel Costs		
US dollars	**2020**	2019
Dollars per MWh	**101**	121

Average fuel cost per MWh decreased in Q3 2020 and year-to-date, compared to the same periods in 2019, due to 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 September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Operating revenues – regulated gas (1)	**$ 146**	$ 156	**$ 546**	$ 604
Operating revenues – non-regulated	**3**	3	**9**	9
Total operating revenue	**$ 149**	$ 159	**$ 555**	$ 613
Regulated cost of natural gas	**30**	40	**141**	188
Income from equity investments	**3**	4	**10**	14
Contribution to consolidated net income	**$ 16**	$ 20	**$ 87**	$ 102
Contribution to consolidated net income – CAD	**$ 20**	$ 25	**$ 117**	$ 132
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.08**	$ 0.10	**$ 0.47**	$ 0.55
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.32**	$ 1.34	**$ 1.35**	$ 1.33
EBITDA	**$ 52**	$ 51	**$ 213**	$ 227
EBITDA – CAD	**$ 69**	$ 66	**$ 288**	$ 299

(1) Operating revenues – regulated gas includes $12 million of finance income from Brunswick Pipeline (2019 - $13 million) for the three months ended September 30, 2020 and $34 million (2019 - $34 million) for the nine months ended September 30, 2020; 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 September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
PGS	**$ 10**	$ 10	**$ 39**	$ 42
NMGC	**(5)**	(1)	**18**	31
Other	**11**	11	**30**	29
Contribution to consolidated net income	**$ 16**	$ 20	**$ 87**	$ 102

Net Income

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

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2019	**$ 20**	**$ 102**
Decreased gas operating revenues - see Operating Revenues - Regulated Gas below	(10)	(49)
Decreased gas operating revenues as a result of recognition of tax reform benefits at NMGC in Q2 2019	-	(9)
Recognition of tax benefits related to change in treatment of NOL carryforwards at NMGC in Q3 2019	(5)	(5)
Decreased cost of natural gas sold - See Regulated Cost of Natural Gas below	10	47
Other	1	1
Contribution to consolidated net income – 2020	**$ 16**	**$ 87**

Gas Utilities and Infrastructure's CAD contribution to consolidated net income decreased $5 million compared to Q3 2019. Year-to-date, Gas Utilities and Infrastructure's CAD contribution to consolidated net income decreased $15 million compared to 2019. The decrease in both periods was due to NMGC's recognition of tax benefits related to the change in treatment of NOL carryforwards in Q3 2019 and lower PGS base revenues due to the impacts of COVID-19 on commercial sales. The decrease was partially offset by higher customer growth, increased AFUDC earnings and higher return on investment in the cast iron and bare steel replacement rider at PGS and lower OM&G expenses at NMGC. Year-to-date, the decrease was also due to NMGC's recognition of tax reform benefits in Q2 2019.

The foreign exchange rate had minimal impact for the three months ended September 30, 2020 and year-to-date 2020.

Operating Revenues – Regulated Gas

Gas Utilities and Infrastructure's operating revenues decreased $10 million to $146 million in Q3 2020, compared to $156 million in Q3 2019. Year-to-date operating revenues decreased $58 million to $546 million, compared to $604 million in the same period in 2019. The decrease in both periods resulted from lower clause-related revenues, lower off-system sales at PGS and lower commercial sales related to the COVID-19 pandemic at PGS. This decrease was partially offset by customer growth at PGS. Year-to-date the decrease was also due to the regulatory approval allowing NMGC to retain $9 million USD in tax reform benefits in Q2 2019.

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

Q3 Gas Revenues
millions of US dollars

		2020		2019
Residential	**$**	**57**	$	58
Commercial		**40**		43
Industrial (1)		**10**		9
Other (2)		**27**		33
Total (3)	**$**	**134**	$	143

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $12 million of finance income from Brunswick Pipeline (2019 – $13 million).

YTD Gas Revenues
millions of US dollars

		2020		2019
Residential	**$**	**250**	$	270
Commercial		**144**		162
Industrial (1)		**30**		28
Other (2)		**88**		110
Total (3)	**$**	**512**	$	570

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $34 million of finance income from Brunswick Pipeline (2019 – $34 million).

Q3 Gas Volumes
Therms (millions)

	2020	2019
Residential	**38**	35
Commercial	**150**	165
Industrial	**417**	386
Other	**68**	93
Total	**673**	679

YTD Gas Volumes
Therms (millions)

	2020	2019
Residential	**273**	275
Commercial	**547**	605
Industrial	**1,198**	1,106
Other	**239**	229
Total	**2,257**	2,215

Regulated Cost of Natural Gas

Regulated cost of natural gas decreased $10 million to $30 million in Q3 2020, compared to $40 million in Q3 2019. Year-to-date, regulated cost of natural gas decreased $47 million to $141 million in Q3 2020, compared to $188 million in the same period in 2019. The decrease in both periods was due to lower commodity costs at PGS and NMGC, lower volume of commercial sales and lower volume of off-system sales at PGS.

Gas sales by type are summarized in the following table:

Q3 Gas Volumes by Type
Therms (millions)

	2020	2019
System supply	**92**	110
Transportation	**581**	569
Total	**673**	679

YTD Gas Volumes by Type
Therms (millions)

	2020	2019
System supply	**493**	519
Transportation	**1,764**	1,696
Total	**2,257**	2,215

Other

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30 **2020**	2019	Nine months ended September 30 **2020**	2019
Marketing and trading margin (1) (2)	**$ (12)**	$ (23)	**$ 16**	$ 3
Electricity and capacity sales (3)	**6**	-	**12**	116
Other non-regulated operating revenue	**4**	12	**13**	30
Total operating revenues – non-regulated	**$ (2)**	$ (11)	**$ 41**	$ 149
Intercompany revenue (4)	**3**	4	**10**	17
Non-regulated fuel for generation and purchased power (5)	**5**	-	**12**	66
Income from equity investments	**-**	8	**17**	25
Interest expense, net	**72**	81	**230**	256
Adjusted contribution to consolidated net income (loss)	**$ (70)**	$ (112)	**$ (229)**	$ (228)
Gain on sale and impairment charges, net of tax	**-**	-	**283**	-
After-tax derivative mark-to-market gain (loss)	**(82)**	(67)	**(95)**	(8)
Contribution to consolidated net income (loss)	**$ (152)**	$ (179)	**$ (41)**	$ (236)
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.28)**	$ (0.46)	**$ (0.93)**	$ (0.95)
Contribution to consolidated earnings per common share – basic	**$ (0.61)**	$ (0.74)	**$ (0.17)**	$ (0.99)
Adjusted EBITDA	**$ (22)**	$ (42)	**$ (25)**	$ 7

(1) Marketing and trading margin represents EES's purchases and sales of natural gas and electricity, pipeline and storage capacity costs and energy asset management services' revenues.
(2) Marketing and trading margin excludes a pre-tax mark-to-market loss of $131 million in Q3 2020 (2019 - $102 million loss) and a loss of $155 million year-to-date (2019 – $19 million loss).
(3) Electricity and capacity sales exclude a pre-tax mark-to-market of nil in Q3 2020 (2019 - nil) and year-to-date of nil (2019 – $2 million gain).
(4) Intercompany revenue consists of interest from Brunswick Pipeline and M&NP.
(5) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market gain of $3 million in Q3 2020 (2019 - $2 million gain) and a gain of $3 million year-to-date (2019 – $1 million loss).

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

For the millions of Canadian dollars	Three months ended September 30 **2020**	2019	Nine months ended September 30 **2020**	2019
Emera Energy	**$ (12)**	$ (14)	**$ 2**	$ 19
Corporate	**(57)**	(99)	**(230)**	(247)
Other	**(1)**	1	**(1)**	-
Adjusted contribution to consolidated net income (loss)	**$ (70)**	$ (112)	**$ (229)**	$ (228)

Net Income

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

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income (loss) – 2019	**$**	**(179)**	**$**	**(236)**
Increased marketing and trading margin - see Emera Energy		11		13
Decreased other income due to 2019 gain on sale of property in Florida, net of tax		-		(10)
Decreased interest expense primarily due to lower interest rates and repayment of long-term debt		9		20
Revaluation of net deferred income tax assets resulting from the enactment of a lower Nova Scotia provincial corporate income tax rate in Q1 2020, including $2 million recovery related to mark-to-market		-		(11)
Decreased income tax recovery primarily due to decreased losses before provision for income taxes, partially offset by the impact of Emera's effective state tax rate		(12)		(2)
Decreased preferred stock dividends due to timing		22		11
Impact of sale of NEGG and Bayside Power, net of tax		(1)		(22)
Gain on sale of Maine and impairment charges, net of tax		-		283
Increased mark-to-market loss, net of tax, quarter-over-quarter, primarily due to changes in existing positions and higher amortization of gas transportation assets in 2020. Increased mark-to-market loss, net of tax, year-over-year due to higher amortization on gas transportation assets in 2020 and a larger reversal of mark-to-market losses in 2019		(15)		(89)
2019 corporate share of the unrecoverable loss at GBPC facilities		9		9
Decreased income from Bear Swamp equity investment due to reduced energy deliveries resulting from a third-party transmission line outage, lower New England capacity prices and less favourable energy market conditions		(8)		(8)
Other		12		1
Contribution to consolidated net income (loss) – 2020	**$**	**(152)**	**$**	**(41)**

Excluding the increase in mark-to-market loss, gain on sale, and impairment charges recognized on certain other assets, Other's contribution to consolidated net income increased $42 million to a loss of $70 million in Q3 2020, compared to the same period in 2019. Year-to-date, Other's contribution decreased $1 million to a loss of $229 million compared to 2019. Year-to-date and quarter-over quarter, the increases were due to timing of preferred stock dividends, higher marketing and trading margin, lower interest and the recognition of the corporate share of the unrecoverable loss on GBPC's facilities in 2019, partially offset by lower income tax recovery. Year-over-year, the decrease was also due to the impact of the sale of NEGG and Bayside Power, revaluation of net deferred income tax assets resulting from the Q1 2020 enactment of a lower Nova Scotia provincial corporate income tax rate and the 2019 sale of property in Florida.

Emera Energy

Marketing and trading margin increased $11 million to a loss of $12 million in Q3 2020, compared to a loss of $23 million in Q3 2019 due to lower fixed commitments for gas transportation and storage assets and increased periods of volatility in Q3 2020, compared to Q3 2019, which improved market opportunity.

Year-to-date, margin increased $13 million to $16 million in 2020, compared to $3 million for the same period in 2019. This increase was due to more favourable hedges in 2020 compared to 2019, partially offset by less favourable winter market conditions, specifically warmer than normal weather, lower natural gas prices and low volatility in Q1 2020 when compared to Q1 2019.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash from its various regulated and non-regulated energy investments. Utility customer bases are diversified by both sales volumes and revenues among customer classes. Emera's non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company's ability to generate cash include general economic downturns in markets served by Emera, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets and changes in environmental legislation. Emera's subsidiaries 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.

During the three and nine months ended September 30, 2020, the effects of the ongoing COVID-19 pandemic including the resulting government measures to address this pandemic have resulted in economic slowdowns in all markets served by Emera. The pace and strength of economic recovery is uncertain and may vary among jurisdictions.

The pandemic has generally resulted in lower load and higher operating costs than what otherwise would have been experienced at the Company's utilities. Some of Emera's utilities have been impacted more than others. However, on a consolidated basis, these unfavourable impacts have not had a material impact to consolidated net earnings to date. Refer to the "Business Overview and Outlook – COVID-19 Pandemic" section for further discussion. The ongoing economic impact of the pandemic may affect customers' ability to pay. As a result of the temporary suspension of disconnections, the Company's utilities experienced an increase in the aging of customer receivables. This trend has begun to reverse as normal disconnection processes resume. To date, there have been no significant customer defaults as a result of bankruptcies with many customer accounts secured by deposits. The full impact of potential credit losses due to customer non-payment is not known at this time; however, at September 30, 2020, the increase in allowance for credit losses related to the increase in the aging of customer receivables was not material. The utilities are continuing to monitor customer accounts and are continuing to work with customers on payment arrangements.

The extent of the future impact of COVID-19 on the Company's operating cash flow cannot be predicted at this time and will depend on future developments, including the duration and severity of the pandemic, further potential government actions and future economic activity and energy usage. The Company currently expects to continue to have adequate liquidity given its cash position, existing bank facilities, and access to capital, but will continue to monitor the impact of COVID-19 on future cash flows.

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 has a $7.4 billion capital investment plan over the 2021-to-2023 period and the potential for additional capital opportunities of $1.2 billion over the same period. This plan includes significant rate base investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. Capital expenditures at the regulated utilities are subject to regulatory approval. The extent of the future impact of COVID-19 on the profile of the Company's capital plan cannot be predicted at this time due to reasons discussed earlier. The Company has flexibility with respect to its capital investment plan and will continue to monitor current events and related impacts of COVID-19.

Emera plans to use cash from operations, debt raised at the utilities, and proceeds from the Emera Maine sale to support normal operations, repayment of existing debt and capital requirements. Debt raised at certain of the Company's utilities is subject to applicable regulatory approvals. Equity requirements in support of the Company's capital investment plan will predominantly be funded in the equity capital markets through the dividend reinvestment plan and the issuance of common and preferred equity. The Company's future access to capital may be impacted by possible COVID-19 related market disruptions. Refer to the "Risk Management and Financial Instruments" section for updated risk disclosure.

Emera has credit facilities with varying maturities that cumulatively provide $3.3 billion of credit, with approximately $1.6 billion undrawn and available at September 30, 2020. The Company was holding a cash balance of $335 million at September 30, 2020. Refer to the “Debt Management” section below for further details. Refer to notes 19 and 20 in the condensed consolidated interim financial statements for additional information regarding the credit facilities.

As at September 30, 2020, Emera had $145 million CAD ($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 October 2020.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the nine months ended September 30, 2020 and 2019 include:

millions of Canadian dollars		**2020**		2019		Change
Cash, cash equivalents, restricted cash and assets held for sale, beginning of period	**$**	**274**	$	372	$	(98)
Provided by (used in):						
Operating cash flow before change in working capital		**1,101**		1,182		(81)
Change in working capital		**139**		128		11
Operating activities		**1,240**		1,310		(70)
Investing activities		**(536)**		(786)		250
Financing activities		**(595)**		(546)		(49)
Effect of exchange rate changes on cash, cash equivalents, restricted cash and cash included in assets held for sale		**(48)**		(13)		(35)
Cash, cash equivalents, and restricted cash, end of period	**$**	**335**	$	337	$	(2)

Cash Flow from Operating Activities

Net cash provided by operating activities decreased $70 million to $1,240 million for the nine months ended September 30, 2020, compared to $1,310 million for the same period in 2019.

Cash from operations before changes in working capital decreased $81 million. The decrease was primarily due to the impact of the sale of Emera Maine in Q1 2020, lower earnings at NSPI, and lower over-recovery from customers of clause-related costs at Tampa Electric and PGS. This was partially offset by higher base revenue at Tampa Electric.

Changes in working capital increased operating cash flows by $11 million. The increase was due to favourable changes in cash collateral at NSPI, and the receipt of a 2019 income tax refund at NSPI in 2020. This was partially offset by a refund of $146 million ($109 million USD) of alternative minimum tax credit carryforwards received in April 2019, decrease in fuel inventory at NSPI, and unfavourable changes in cash collateral at Emera Energy.

Cash Flow from Investing Activities

Net cash used in investing activities decreased $250 million to $536 million for the nine months ended September 30, 2020, compared to cash used of $786 million for the same period in 2019. In 2020, Emera received proceeds of $1.4 billion on the sale of Emera Maine, compared to proceeds of $866 million on dispositions in 2019, primarily from the sale of the NEGG and Bayside facilities. This increase in proceeds was partially offset by higher capital expenditures in 2020.

Capital expenditures for the nine months ended September 30, 2020, including AFUDC, were $1,967 million compared to $1,662 million for the same period in 2019. Details of the 2020 capital spend by segment are shown below:

- $1,029 million - Florida Electric Utility (2019 – $919 million);
- $253 million - Canadian Electric Utilities (2019 – $263 million);
- $124 million - Other Electric Utilities (2019 – $127 million);
- $559 million - Gas Utilities and Infrastructure (2019 – $295 million); and
- $2 million - Other (2019 – $58 million).

Cash Flow from Financing Activities

Net cash used in financing activities increased $49 million to $595 million for the nine months ended September 30, 2020, compared to $546 million for the same period in 2019. The increase was due to net repayment of debt at TECO Finance, higher net repayments of Emera and NSPI's committed credit facilities, and lower proceeds from the issuance of long-term debt at NSPI. These were partially offset by a 2019 repayment of corporate long-term debt.

Contractual Obligations

As at September 30, 2020, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2020	2021	2022	2023	2024	Thereafter	Total
Long-term debt principal	$ 28	$ 1,715	$ 425	$ 833	$ 691	$ 10,504	$ 14,196
Interest payment obligations (1)	264	607	574	550	535	7,082	9,612
Purchased power (2)	74	218	218	216	219	2,024	2,969
Transportation (3)	157	467	396	337	307	3,028	4,692
Pension and post-retirement obligations (4)	7	33	29	29	97	259	454
Capital projects (5)	222	195	104	91	-	-	612
Fuel, gas supply and storage	177	240	44	6	1	-	468
Asset retirement obligations	2	24	1	1	1	382	411
Long-term service agreements (6)	13	30	30	27	25	96	221
Equity investment commitments (7)	-	-	240	-	-	-	240
Leases and other (8)	4	19	18	18	16	128	203
Demand side management	8	42	43	-	-	-	93
Long-term payable	1	5	5	5	-	-	16
	$ 957	$ 3,595	$ 2,127	$ 2,113	$ 1,892	$ 23,503	$ 34,187

(1) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at September 30, 2020, including any expected required payment under associated swap agreements.

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

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

(4) The estimated contractual obligation is calculated as the current legislatively required contributions to the registered funded pension plans (excluding the possibility of wind-up), plus the estimated costs of further benefit accruals contracted under NSPI's Collective Bargaining Agreement and estimated benefit payments related to other unfunded benefit plans.

(5) Includes $422 million of commitments related to Tampa Electric's solar, Big Bend Power Station modernization and AMI projects.

(6) 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.

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

(8) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

On March 17, 2020, Nalcor announced that it had paused construction activities at the Muskrat Falls site in response to the COVID-19 pandemic. As a result of the effects of COVID-19 on project execution, Nalcor declared force majeure under various project contracts, including formal notification to NSPML. Nalcor resumed work in May 2020. Nalcor achieved first power on the first of four generators at Muskrat Falls on September 22, 2020 and continues to work toward project commissioning in 2021.

NSPML expects to file a final cost assessment with the UARB upon commencement of the NS Block of energy from Muskrat Falls. On July 31, 2020, NSPML filed an interim assessment application with the UARB requesting recovery of 2021 costs of approximately $172 million, resulting in an additional $27 million to be collected from NSPI. A decision from the UARB is expected in Q4 2020.

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 2020 is $145 million subject to a $10 million holdback and as at September 30, 2020, $79 million has been paid. As part of NSPI’s 2020-2022 fuel stability plan, rates have been set to include the $145 million approved for 2020 and amounts of $164 million and $162 million for 2021 and 2022, respectively. Any difference between the amounts included in the NSPI fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM. The timing and amounts payable to NSPML for the remainder of the 37-year commitment period are dependent on regulatory filings with the UARB.

Emera has committed to obtain certain transmission rights for Nalcor Energy, if requested, to enable them to transmit energy which is not otherwise used in Newfoundland or Nova Scotia. This energy could be transmitted from Nova Scotia to New England energy markets beginning at first commercial power of the Muskrat Falls hydroelectric generating facility and related transmission assets when Nalcor commences delivery of the NS Block, and continuing for 50 years. As transmission rights are contracted, Emera includes the obligations within “Leases and other” in the above table.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.3 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. – Unsecured committed revolving credit facility	June 2024	$ 900	$ 456	$ 444
Emera Inc. – Unsecured non-revolving facility	December 2020	400	400	-
TECO Finance, Inc. – in USD – Unsecured committed revolving credit facility	March 2022	400	301	99
NSPI – Unsecured committed revolving credit facility	October 2024	600	4	596
TEC – in USD – Unsecured committed revolving credit facility (1)	March 2022	400	196	204
TEC – in USD – Accounts receivable collateralized borrowing facility (1)	March 2021	150	40	110
TEC – in USD – Unsecured non-revolving facility (1)	February 2021	300	300	-
NMGC – in USD – Unsecured committed revolving credit facility	March 2022	125	12	113
Other – in USD – Unsecured committed revolving credit facilities	Various	32	21	11

(1) These facilities are available for use by Tampa Electric and PGS. At September 30, 2020, Tampa Electric had utilized $392 million USD and PGS had utilized $144 million USD of the facilities.

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly, and the Company is in compliance with its covenant requirements as at September 30, 2020.

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

Florida Electric Utilities

On February 6, 2020, TEC entered into a $300 million USD non-revolving credit agreement with a maturity date of February 4, 2021. The credit agreement contains customary representations and warranties, events of default, financial and other covenants and bears interest at LIBOR, prime rate or the federal funds rate, plus a margin.

Canadian Electric Utilities

On April 24, 2020, NSPI completed a $300 million 30-year unsecured notes issuance. The notes bear interest at a rate of 3.31 per cent and have a maturity date of April 25, 2050.

Other Electric Utilities

On May 20, 2020, GBPC entered into a $22 million USD non-revolving term loan with a maturity date of May 20, 2025. The loan bears interest at a rate of 90-day LIBOR plus a margin. On May 22, 2020, proceeds from this loan were used to repay $22 million USD senior notes upon maturity.

On May 20, 2020, GBPC entered into a $15 million BSD ($15 million USD) non-revolving term loan with a maturity date of May 20, 2025. The loan bears interest at a rate of 4.00 per cent.

At September 30, 2020, BLPC had drawn $67 million BBD ($33 million USD) against a $110 million BBD ($55 million USD) non-revolving term loan. The loan bears interest at a rate of 2.05 per cent and has a 5-year term.

Other

On February 28, 2020, TECO Energy/Finance extended the maturity date of its $500 million USD credit facility from March 5, 2020 to July 3, 2020. There were no other significant changes in commercial terms from the prior agreement. Using funds from the sale of Emera Maine, on April 3, 2020, TECO Energy/Finance repaid $200 million USD of the term loan and the remaining $300 million USD was repaid on June 30, 2020.

On March 13, 2020, TECO Finance repaid a $300 million USD note upon maturity. The note was repaid using existing credit facilities.

Credit Ratings

On July 8, 2020, Fitch Ratings assigned a first-time long-term issuer default rating of BBB+ to NMGC. The rating outlook is stable.

On March 24, 2020, S&P changed its issuer rating for Emera and TECO to BBB from BBB+ and at the same time changed the outlook on both to stable from negative. S&P also affirmed its BBB+ issuer ratings for TEC and NSPI and changed the outlook on both to stable from negative.

Guarantees and Letters of Credit

Emera’s guarantees and letters of credit are consistent with those disclosed in the Company’s 2019 audited annual consolidated financial statements, with updates as noted below:

The Company has standby letters of credit and surety bonds in the amount of $54 million USD (December 31, 2019 - $82 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 Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The expiry date of this letter of credit was extended to June 2021. The amount committed as at September 30, 2020 was $63 million (December 31, 2019 - $52 million).

Emera Inc. has issued a guarantee of up to $35 million USD relating to outstanding notes of GBPC. The guarantee for the notes will expire in May 2023.

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 September 30, 2020 (2019 - $26 million) and $82 million for the nine months ended September 30, 2020 (2019 - $80 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 $2 million for the three months ended September 30, 2020 (2019 - $16 million) and $13 million for the nine months ended September 30, 2020 (2019 - $50 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at September 30, 2020 and at December 31, 2019.

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 2019 annual MD&A, except for the following:

Public Health Risk

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, or a fear of any of the foregoing, could adversely impact the Company, including by causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns (including as a result of government regulation and prevention measures), which could have a negative impact on the Company's operations.

Any adverse changes in general economic and market conditions arising as a result of a public health threat could negatively impact demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; which could result in a material adverse effect on the Company's business.

The extent of the evolving COVID-19 pandemic and its future impact on the Company is uncertain. The Company maintains pandemic and business contingency plans in each of its operations to manage and help mitigate the impact of any such public health threat. The Company's top priority continues to be the health and safety of its customers and employees. In Q1 2020, Emera activated its company-wide pandemic and business continuity plans, including travel restrictions, directing employees to work remotely whenever possible, restricting access to operating facilities, physical distancing and implementing additional protocols (including the expanded use of personal protective equipment) for work within customers' premises. The Company is monitoring recommendations by local and national public health authorities related to COVID-19 and is adjusting operational requirements as needed.

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	**September 30 2020**	December 31 2019
Derivative instrument liabilities (current and long-term liabilities)	**$ -**	$ (1)
Net derivative instrument liabilities	**$ -**	$ (1)

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 September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Operating revenues – regulated	**$ -**	$ (1)	**$ (2)**	$ (3)
Effective net losses	**$ -**	$ (1)	**$ (2)**	$ (3)

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

Regulatory Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**September 30 2020**	December 31 2019
Derivative instrument assets (current and other assets)	**$ 27**	$ 28
Regulatory assets (current and other assets)	**68**	80
Derivative instrument liabilities (current and long-term liabilities)	**(68)**	(78)
Regulatory liabilities (current and long-term liabilities)	**(25)**	(42)
Net asset (liability)	**$ 2**	$ (12)

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 September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Regulated fuel for generation and purchased power (1)	**$ (8)**	$ -	**$ (18)**	$ 7
Net gains (losses)	**$ (8)**	$ -	**$ (18)**	$ 7

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

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	**September 30 2020**	December 31 2019
Derivative instrument assets (current and other assets)	**$ 51**	$ 58
Derivative instrument liabilities (current and long-term liabilities)	**(365)**	(291)
Net derivative instrument liability	**$ (314)**	$ (233)

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 September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Operating revenue - non-regulated	**$ (187)**	$ (69)	**$ 35**	$ 180
Non-regulated fuel for purchased power	**1**	1	**(3)**	(4)
Net gains (losses)	**$ (186)**	$ (68)	**$ 32**	$ 176

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	**September 30 2020**	December 31 2019
Derivative instrument assets (current and other assets)	**$ 11**	$ 1
Derivative instrument liabilities (current and long-term liabilities)	**(3)**	-
Net derivative instrument assets	**$ 8**	$ 1

Other Derivatives Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Operating, maintenance and general	**$ 4**	$ 11	**$ (3)**	$ 34
Other income (expense)	**5**	-	**5**	-
Total gains	**$ 9**	$ 11	**$ 2**	$ 34

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 September 30, 2020, 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 September 30, 2020 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 USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, allowance for credit losses, 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. 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, with any adjustments recognized in income in the year they arise. Management has analyzed the impact of the COVID-19 pandemic on its estimates and judgements and concluded that no material adjustments are required at September 30, 2020.

Goodwill Impairment Assessments

Management considered whether the potential impacts of the COVID-19 pandemic on future earnings required testing for goodwill impairment in Q3 2020 and determined that it is more likely than not that the fair value of reporting units that include goodwill exceeded their respective carrying amounts as of September 30, 2020.

As of September 30, 2020, $5.9 billion of Emera’s goodwill was related to TECO Energy (Tampa Electric, PGS and NMGC reporting units). Given the significant excess of fair value over carrying amounts calculated for these reporting units as of the last quantitative test performed in Q4 2019, management does not expect the COVID-19 pandemic to have an impact on the goodwill associated with these reporting units.

As of September 30, 2020, $72 million of Emera’s goodwill was related to GBPC. The calculated goodwill for this reporting unit is more sensitive to changes in forecasted future earnings. Adverse impacts to earnings in the future as a result of COVID-19 could cause impairment; however, the impact of COVID-19 on future earnings cannot be reasonably determined or estimated at this time. No impairment has been recorded for the three and nine months ended September 30, 2020 associated with this goodwill.

Long-Lived Assets Impairment Assessments

Management considered whether the potential impacts of the COVID-19 pandemic on undiscounted future cash flows could indicate that long-lived assets are not recoverable. As at September 30, 2020, there are no indications of impairment of Emera's long-lived assets. The impact of COVID-19 could cause the Company to impair long-lived assets in the future; however, there is currently no indication that future cash flows would be impacted to a point where the Company's long-lived assets would not be recoverable.

Impairment charges of $nil and $25 million ($26 million after tax) were recognized on certain assets for the three and nine months ended September 30, 2020, respectively.

Pension and Other Post-Retirement Employee Benefits

The COVID-19 pandemic could impact key actuarial assumptions used to account for employee post-retirement benefits including the anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation, benefit costs and annual pension funding requirements. Fluctuations in actual equity market returns and changes in interest rates as a result of the COVID-19 pandemic may also result in changes to pension costs and funding in future periods.

The extent of the future impact of COVID-19 on the Company's financial results and business operations cannot be predicted at this time and will depend on future developments, including the duration and severity of the pandemic, further potential government actions and future economic activity and energy usage. Actual results may differ significantly from these estimates.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2020, are described as follows:

Measurement of Credit Losses on Financial Instruments

The Company adopted Accounting Standard Update ("ASU") 2016-13, *Measurement of Credit Losses on Financial Instruments* effective January 1, 2020. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. The adoption of the standard resulted in a $7 million decrease to retained earnings in the condensed consolidated interim financial statements as of January 1, 2020.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The ASUs that have been issued, but are not yet effective, are consistent with those disclosed in the Company's 2019 audited consolidated financial statements, with updates noted below.

Facilitation of the Effects of Reference Rate Reform on Financial Reporting

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting.* The standard provides optional expedients and exceptions for applying USGAAP to contract modifications and hedging relationships that reference LIBOR or another rate that is expected to be discontinued. The guidance was effective as of the date of issuance and entities may elect to apply the guidance prospectively through December 31, 2022. The Company implemented a project plan in Q2 2020 and has identified impacted financial instruments which primarily include debt and hedging contracts. The Company is in the process of evaluating the impact of adoption of the standard, if elected, on its consolidated financial statements.

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity

In August 2020, the FASB issued ASU 2020-06, *Debt - Debt with Conversion and Other Options (Subtopic 470-20)* and *Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40).* The standard reduces the number of accounting models for convertible debenture debt instruments and convertible preferred stock, in addition to amending disclosure requirements. The standard also updates guidance for the derivative scope exception for contracts in an entity's own equity and the related earnings per share guidance. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2021. Early adoption is permitted, but no earlier than fiscal years beginning after December 15, 2020. The standard will be applied through either a modified retrospective method of transition or a fully retrospective method of transition. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

Guaranteed Debt Securities Disclosure Requirements

In October 2020, the FASB issued ASU 2020-09, *Debt (Topic 470): Amendments to SEC Paragraphs pursuant to SEC Release No. 33-10762*. The change in the standard aligns with new SEC rules relating to changes to the disclosure requirements for certain registered debt securities that are guaranteed. The changes include simplifying and focusing the disclosure models, enhancing certain narrative disclosures and permitting the disclosures to be made outside of the financial statements. The guidance will be effective for annual reports filed for fiscal years ending after January 4, 2021, with early adoption permitted. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of Canadian dollars (except per share amounts)	**Q3 2020**	Q2 2020	Q1 2020	Q4 2019	Q3 2019	Q2 2019	Q1 2019	Q4 2018
Operating revenues	**$ 1,163**	$ 1,169	$ 1,637	$ 1,616	$ 1,299	$ 1,378	$ 1,818	$ 1,799
Net income attributable to common shareholders	**84**	58	523	193	55	103	312	231
Adjusted net income attributable to common shareholders	**166**	118	193	145	122	130	224	167
Earnings per common share – basic	**0.34**	0.24	2.14	0.79	0.23	0.43	1.32	0.98
Earnings per common share – diluted	**0.34**	0.23	2.13	0.80	0.23	0.43	1.32	0.98
Adjusted earnings per common share – basic	**0.67**	0.48	0.79	0.60	0.51	0.54	0.95	0.71

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 demand for energy and the cost of service. Quarterly results could also be affected by items outlined in the “Significant Items Affecting Earnings” section. In 2020, quarterly results include the impact of the COVID-19 pandemic commencing in March 2020. Refer to the “Business Overview and Outlook” section for further details.