Management's Discussion & Analysis

As at February 16, 2021

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments ("Emera") during the fourth quarter of 2020 relative to the same quarter in 2019; the full year of 2020 relative to 2019 and selected financial information for 2018; and its financial position as at December 31, 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 annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2020. 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 December 31, 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. For further detail, refer to the "Significant Items Affecting Earnings" and "Developments" sections.

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, carbon emissions reduction goals, 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 include without limitation: 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 continues to be 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’s $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, results in a forecasted rate base growth of 7.5 per cent to 8.5 per cent through to 2023. The capital investment plan continues to include significant investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. Emera’s capital investment plan 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 equity capital markets through the dividend reinvestment plan and 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 investments 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, digitization, decarbonization, complex regulatory environments and decentralized generation.

Customers are looking for more choice, better control, and enhanced reliability in a time where costs of decentralized generation and storage have become more competitive in some regions. Advancing technologies are transforming the way utilities interact with their customers and generate and transmit energy. In addition, 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 all these trends. Emera’s strategy is to fund investments in renewable energy 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 safely delivering cleaner, reliable, and affordable energy for its customers.

Building on its decarbonization progress over the past 15 years, Emera is continuing its efforts by establishing clear carbon reduction goals and a vision to achieve net-zero carbon emissions by 2050.

This vision is inspired by Emera’s strong track record, the Company’s experienced team, and a clear path to Emera’s interim carbon goals. With existing technologies and resources and the benefit of supportive regulatory decisions, Emera plans and expects to achieve the following goals compared to corresponding 2005 levels:

- A 55 per cent reduction in carbon emissions by 2025.
- An 80 per cent reduction in coal usage by 2023 and the retirement of Emera’s last existing coal unit no later than 2040.
- At least an 80 per cent reduction in carbon emissions by 2040.

Emera seeks to achieve these goals and realize its net-zero vision while remaining focused on maintaining affordability, enhancing reliability, adopting emerging technologies and working constructively with policymakers, regulators, partners, investors, and Emera's communities.

Emera is committed to world-class safety, operational excellence, good governance, excellent customer service, reliability, being an employer of choice, and building constructive relationships.

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, the gain on the sale of Emera Maine in 2020 and impairment charges.

The MTM adjustments are a result of the following:

- the MTM 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 MTM 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 MTM adjustments related to an interest rate swap in Brunswick Pipeline;
- the MTM adjustments related to equity securities held in BLPC and Emera Reinsurance, a captive reinsurance company in the Other segment; and
- the MTM 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 MTM 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 MTM adjustments for evaluation of performance and incentive compensation. For further detail on MTM adjustments, refer to the "Consolidated Financial Review" section and the "Financial Highlights" sections for Other Electric Utilities and Other segments.

In 2020, the Company recognized a gain on the sale of Emera Maine. Management believes excluding this 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 detail 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 only includes earnings from Emera Maine up to the date of its sale in Q1 2020.

In 2019 and 2020, the Company recognized certain non-cash impairment charges. Management believes excluding from net income the effect of these charges better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the Company. For further details, refer to the "Significant Items Affecting Earnings", "Financial Highlights – Other Electric Utilities" and "Financial Highlights – Other" sections.

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

For the millions of Canadian dollars (except per share amounts)		Three months ended December 31			Year ended December 31	
		2020	2019	**2020**	2019	2018
Net income attributable to common shareholders	**$**	**273** $	193 **$**	**938** $	663 $	710
Gain on sale, net of tax and transaction costs	**$**	**-** $	- **$**	**309** $	- $	-
Impairment charges, net of tax	**$**	**-** $	(34) **$**	**(26)** $	(34) $	-
After-tax MTM gains (losses)	**$**	**85** $	82 **$**	**(10)** $	76 $	39
Adjusted net income attributable to common shareholders	**$**	**188** $	145 **$**	**665** $	621 $	671
Earnings per common share – basic	**$**	**1.09** $	0.79 **$**	**3.78** $	2.76 $	3.05
Adjusted earnings per common share – basic	**$**	**0.75** $	0.60 **$**	**2.68** $	2.59 $	2.88

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 MTM, the gain on sale of Emera Maine and impairment charges, 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 December 31			Year ended December 31	
		2020	2019	**2020**	2019	2018
Net income (1)	**$**	**284** $	192 **$**	**984** $	710 $	747
Interest expense, net		**159**	181	**679**	738	713
Income tax expense		**57**	43	**341**	61	69
Depreciation and amortization		**217**	225	**881**	903	916
EBITDA		**717**	641	**2,885**	2,412	2,445
Gain on sale (excluding transaction costs)		**-**	-	**585**	-	-
Impairment charges		**-**	(34)	**(25)**	(34)	-
MTM gains (losses), excluding income tax and interest		**118**	118	**(18)**	107	58
Adjusted EBITDA	**$**	**599** $	557 **$**	**2,343** $	2,339 $	2,387

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

2020

TECO Guatemala Holdings (“TGH”) International Arbitration and Award

On November 24, 2020, a payment was made by the Republic of Guatemala related to an investment TGH, a wholly owned subsidiary of TECO Energy, indirectly held prior to acquisition by Emera. The payment was based on an award issued by an International Centre for the Settlement of Investment Disputes (“ICSID”) tribunal in 2013. The payment of $49 million ($36 million after tax or $0.15 per common share), net of legal costs was recognized in “Other Income” on the Consolidated Statements of Income. For further detail, refer to note 27 in the consolidated financial statements.

Gain on Sale of Emera Maine 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 Consolidated Statements of Income. For further detail, refer to the “Developments” section.

As a result of the sale, earnings contribution from Emera Maine was $9 million lower in Q4 2020 than in Q4 2019 and $41 million lower for the year ended December 31, 2020.

In addition, impairment charges of $25 million ($26 million after tax) for the year ended December 31, 2020 were recognized on certain other assets.

Earnings Impact of After-Tax MTM Gains and Losses

After-tax MTM gains increased $3 million to $85 million in Q4 2020, compared to $82 million in Q4 2019. For the year ended December 31, 2020, after-tax MTM losses were $86 million more than the $76 million gain recorded in 2019. This increase was due to higher amortization of gas transportation assets in 2020, changes in existing positions and a larger reversal of MTM losses in 2019 at Emera Energy. This was partially offset by gains on foreign exchange cash flow hedges.

Earnings Impact of Q1 2019 Sale of NEGG and Bayside Facilities

Earnings contribution from Emera Energy Generation was $21 million lower for the year ended December 31, 2020 compared to 2019 due to the March 2019 sale of the New England Gas Generating (“NEGG”) and Bayside generation facilities.

2019

GBPC Hurricane Dorian Restoration

In Q3 2019, Hurricane Dorian struck Grand Bahama as a Category 5 hurricane, causing significant damage across the island. Emera’s 2019 earnings decreased by approximately $62 million ($0.26 per common share), as a result of the impact of the hurricane.

In Q4 2019, Emera recognized impairment charges of $34 million, including $30 million related to GBPC's goodwill due to a decrease in expected future cash flows resulting from the impacts of Hurricane Dorian storm recovery and changes in the anticipated long term regulated capital structure of GBPC. This non-cash charge was recorded in "Impairment charges" in the Consolidated Statements of Income. For further information, refer to note 22 to the consolidated financial statements.

GBPC's 2019 earnings decreased $13 million ($0.05 per common share) compared to 2018 due to reduced load as a result of the storm. Emera recorded a corporate loss of $15 million ($0.06 per common share) in 2019, in the Other segment, for the corporate share of the unrecoverable loss on GBPC facilities.

Consolidated Financial Highlights by Business Segment

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
Adjusted Net Income	**2020**	2019	**2020**	2019	2018
Florida Electric Utility	**$ 101**	$ 80	**$ 501**	$ 419	$ 381
Canadian Electric Utilities	**57**	58	**221**	229	218
Other Electric Utilities	**8**	14	**33**	76	89
Gas Utilities and Infrastructure	**45**	51	**162**	183	136
Other	**(23)**	(58)	**(252)**	(286)	(153)
Adjusted net income attributable to common shareholders	**$ 188**	$ 145	**$ 665**	$ 621	$ 671
Gain on sale, net of tax and transaction costs	**-**	-	**309**	-	-
Impairment charges, net of tax	**-**	(34)	**(26)**	(34)	-
After-tax MTM gains (losses)	**85**	82	**(10)**	76	39
Net income attributable to common shareholders	**$ 273**	$ 193	**$ 938**	$ 663	$ 710

The following table highlights the significant changes in adjusted net income from 2019 to 2020:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2019	**$ 145**	**$ 621**
Operating Unit Performance:		
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 load driven by warmer weather, increased mix of residential sales related to the impact of COVID-19, customer growth, and a credit to depreciation expense as a result of a regulatory settlement	21	82
Increased earnings contribution from the Caribbean utilities in Q4 2020 due to continued recovery from Hurricane Dorian at GBPC. Year-over-year, earnings contribution decreased in 2020 due to lower sales related to the impact of COVID-19 and continued recovery from Hurricane Dorian at GBPC	3	(12)
Decreased earnings at NSPI year-over-year due to higher income tax expense, decreased sales volumes due to warmer weather, and lower commercial sales related to the impact of COVID-19. The decrease was partially offset by decreased operating, maintenance and general ("OM&G") expense and increased mix of residential sales related to COVID-19	1	(12)
Decreased earnings due to the sale of Emera Maine in Q1 2020 and the sale of Emera Energy's NEGG and Bayside generation facilities in Q1 2019	(8)	(62)
Tax Related:		
Recognition of corporate income tax recovery deferred as a regulatory liability in 2018 at BLPC	-	10
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)
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	-	(19)
Corporate:		
TGH award, net of tax and legal costs. Refer to the "Significant Items Affecting Earnings" section and note 27 of the consolidated financial statements	36	36
Decreased interest expense in the Other segment primarily due to lower interest rates and repayment of corporate long-term debt	10	30
2019 recognition of corporate loss for the share of the unrecoverable loss on GBPC's facilities related to Hurricane Dorian	6	15
Timing of Q4 preferred share dividend declaration	(11)	-
Other Variances:	(15)	(10)
Adjusted net income – 2020	**$ 188**	**$ 665**

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

For the millions of Canadian dollars			Year ended December 31
	2020	2019	2018
Operating cash flow before changes in working capital	**$ 1,420**	$ 1,598	$ 1,806
Change in working capital	**217**	(73)	(116)
Operating cash flow	**$ 1,637**	$ 1,525	$ 1,690
Investing cash flow	**$ (1,224)**	$ (1,617)	$ (2,190)
Financing cash flow	**$ (372)**	$ 14	$ 344

As at millions of Canadian dollars	**2020**	2019	December 31 2018
Total assets	**$ 31,234**	$ 31,842	$ 32,314
Total long-term debt (including current portion)	**$ 13,721**	$ 14,180	$ 15,411

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

Consolidated Income Statement Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Variance	Year ended December 31		Variance	Year ended December 31
	2020	2019		**2020**	2019		2018
Operating revenues	**$ 1,537**	$ 1,616	$ (79)	**$ 5,506**	$ 6,111	$ (605)	$ 6,524
Operating expenses	**1,148**	1,237	89	**4,359**	4,768	409	5,126
Income from operations	**389**	379	10	**1,147**	1,343	(196)	1,398
Income from equity investments	**36**	36	-	**149**	154	(5)	154
Other income (expenses), net	**75**	1	74	**708**	12	696	(23)
Interest expense, net	**159**	181	22	**679**	738	59	713
Income tax expense	**57**	43	(14)	**341**	61	(280)	69
Net income	**284**	192	92	**984**	710	274	747
Net income attributable to common shareholders	**273**	193	80	**938**	663	275	710
Gain on sale, net of tax and transaction costs	**-**	-	-	**309**	-	309	-
Impairment charges, net of tax	**-**	(34)	34	**(26)**	(34)	8	-
After-tax MTM gains (losses)	**85**	82	3	**(10)**	76	(86)	39
Adjusted net income attributable to common shareholders	**$ 188**	$ 145	$ 43	**$ 665**	$ 621	$ 44	$ 671
Earnings per common share – basic	**$ 1.09**	$ 0.79	$ 0.30	**$ 3.78**	$ 2.76	$ 1.02	$ 3.05
Earnings per common share – diluted	**$ 1.08**	$ 0.80	$ 0.28	**$ 3.78**	$ 2.76	$ 1.02	$ 3.04
Adjusted earnings per common share – basic	**$ 0.75**	$ 0.60	$ 0.15	**$ 2.68**	$ 2.59	$ 0.09	$ 2.88
Dividends per common share declared	**$ 0.6375**	$ -	$ 0.6375	**$ 2.4750**	$ 2.3750	$ 0.1000	$ 2.2825
Adjusted EBITDA	**$ 599**	$ 557	$ 42	**$ 2,343**	$ 2,339	$ 4	$ 2,387

Operating Revenues

For the fourth quarter of 2020, operating revenues decreased $79 million compared to the fourth quarter in 2019. Absent decreased MTM gains of $10 million, operating revenues decreased $69 million due to:

- $64 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020;
- $18 million decrease in the Other Electric Utilities segment due to lower fuel revenues as a result of lower fuel prices at BLPC; and
- $13 million decrease in the Florida Electric Utility segment due lower clause revenues as a result of a decrease in fuel costs, partially offset by the in-service of solar generation projects, colder weather than the prior quarter, a greater mix of residential sales related to COVID-19, and customer growth.

These impacts were partially offset by:

- $13 million increase at NSPI in the Canadian Electric Utilities segment due to higher Maritime Link assessment revenue compared to 2019 and increased residential sales volumes primarily due to the impact of the COVID-19 pandemic, increased industrial sales volumes, and increased fuel-related pricing. This was partially offset by decreased sales volumes due to warmer weather than the prior year and lower commercial sales volumes related to the impact of the COVID-19 pandemic.

For the year ended December 31, 2020, operating revenues decreased $605 million compared to 2019. Absent increased MTM losses of $148 million, operating revenues decreased by $457 million due to:

- $211 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020;
- $127 million decrease in the Florida Electric Utility segment due to lower clause-related 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 related to the impact of COVID-19, warmer weather than the prior year, and customer growth;
- $109 million decrease in the Other segment due to the sale of NEGG and Bayside in Q1 2019;
- $61 million decrease in the Gas Utilities and Infrastructure segment as a result of lower clause-related revenue at PGS, lower off-system sales at PGS, warmer weather than the prior year at NMGC, NMGC's recognition of tax reform benefits in 2019 and lower commercial sales at PGS related to the COVID-19 pandemic. This was partially offset by customer growth at PGS; and
- $59 million decrease in the Other Electric Utilities segment due lower fuel revenue as a result of lower fuel prices at BLPC, the impact of the COVID-19 pandemic at GBPC and BLPC, and the impact of Hurricane Dorian at GBPC.

These impacts were partially offset by:

- $64 million increase at NSPI in the Canadian Electric Utilities segment, due to higher Maritime Link assessment revenue compared to 2019, increased fuel related pricing, and higher mix of residential sales volumes, partially offset by warmer weather than prior year and decreased commercial sales volumes related to the impact of the COVID-19 pandemic.

Operating Expenses

For the fourth quarter of 2020, operating expenses decreased $89 million compared to the fourth quarter of 2019. Absent the $34 million impairment charge in Q4 2019 and decreased MTM losses of $1 million, operating expenses decreased by $54 million due to:

- $49 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020; and
- $25 million decrease in the Florida Electric Utility segment due to lower natural gas prices.

These impacts were partially offset by:

- $11 million increase at NSPI in the Canadian Electric Utilities segment mainly due to higher Maritime Link assessment costs in 2020, partially offset by decreased OM&G expenses and changes in regulatory deferrals; and
- $10 million increase in the Gas Utilities and Infrastructure segment due to higher commodity costs at PGS and NMGC.

For the year ended December 31, 2020, operating expenses decreased $409 million compared to 2019. Absent the decreased impairment charges of $8 million and increased MTM gains of $5 million, operating expenses decreased $396 million due to:

- $196 million decrease in the Florida Electric Utility segment due to lower natural gas prices;
- $148 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 and Bayside facilities in Q1 2019;
- $41 million decrease in the Gas Utilities and Infrastructure segment due to lower commodity costs and lower system supply to customers at PGS and NMGC and lower volume of off-system sales at PGS; and
- $41 million decrease in the Other Electric segment due to lower oil prices at BLPC.

These impacts were partially offset by:

- $61 million increase at NSPI in the Canadian Electric Utilities segment, primarily due to changes in regulatory deferrals, and higher Maritime Links assessments costs in 2020 partially offset by decreased OM&G expenses.

Other Income (Expenses), Net

The increase in other income (expenses), net for the fourth quarter in 2020 was primarily due to the TGH award, 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. For the year ended December 31, 2020, the increase was also due to the pre-tax gain on the sale of Emera Maine.

Interest Expense

Interest expense, net was lower for Q4 2020 and year ended December 31, 2020 compared to 2019 due to lower interest rates and the repayment of corporate debt.

Income Tax Expense

The increase in income tax expense for Q4 2020 compared to the same period in 2019, was primarily due to increased income before provision for income taxes. The increase in income tax expense in 2020, compared to 2019, was primarily due to the gain on the sale of Emera Maine.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For the fourth quarter of 2020, net income attributable to common shareholders was favourably impacted by the $3 million increase in after-tax MTM gains and the 2019 impairment charge of $34 million. Absent favourable MTM changes and the impairment charges, adjusted net income attributable to common shareholders increased $43 million. The increase was due to increased contributions from Florida Electric Utility, the TGH award, decreased corporate interest costs and the 2019 corporate share of unrecoverable loss at GBPC related to Hurricane Dorian. These were partially offset by the timing of preferred share dividends and lower earnings contribution from Emera Maine as a result of its sale.

For the year ended December 31, 2020, net income attributable to common shareholders was favourably impacted by the $309 million after-tax gain on the sale of Emera Maine and the impairment charges, and unfavourably impacted by the $86 million increase in after-tax MTM losses, primarily related to Emera Energy. Absent the net gain on sale of Emera Maine, impairment charges, and the unfavourable MTM changes, adjusted net income attributable to common shareholders increased $44 million. The increase was due to higher earnings contribution from Florida Electric Utility, the TGH award, lower corporate interest costs and the 2019 corporate share of unrecoverable loss at GBPC related to Hurricane Dorian. These were partially offset by lower earnings at Emera Maine as a result of its sale in Q1 2020, reduced earnings at NEGG and Bayside facilities as a result of their sale in Q1 2019, lower earnings contribution from NSPI and the Caribbean utilities, 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 – basic were higher for the fourth quarter and the year ended December 31, 2020 due to increased earnings as discussed above.

Effect of Foreign Currency Translation

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

Earnings from Emera's foreign operations are translated into CAD. In general, Emera's earnings benefit from a weakening CAD and are adversely impacted by a strengthening CAD. 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/USD exchange rates for 2020 and 2019 are as follows:

	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Weighted average CAD/USD	**$ 1.30**	$ 1.32	**$ 1.34**	$ 1.33
Period end CAD/USD exchange rate	**$ 1.27**	$ 1.30	**$ 1.27**	$ 1.30

Strengthening of the CAD exchange rates increased earnings by $1 million and decreased adjusted earnings by $1 million in Q4 2020 compared to Q4 2019. The weakening of the CAD exchange rates increased earnings by $19 million and adjusted earnings by $5 million in 2020, compared to 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 USD currency.

millions of US dollars	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Florida Electric Utility	**$ 76**	$ 61	**$ 372**	$ 316
Other Electric Utilities	**5**	10	**24**	57
Gas Utilities and Infrastructure (1)	**30**	33	**97**	115
	111	104	**493**	488
Other segment (2)	**5**	(28)	**(102)**	(159)
Total (3)	**$ 116**	$ 76	**$ 391**	$ 329

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's USD adjusted net income from Emera Energy Services, Bear Swamp and interest expense on Emera's USD denominated debt and in 2019, net income from NEGG.
(3) Amounts above do not include the impact of MTM.

BUSINESS OVERVIEW AND OUTLOOK

COVID-19 Pandemic

During the year ended December 31, 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 to meet customer demand. The Company’s priorities continue to be the reliable delivery of essential energy services while maintaining 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 primarily due to a change in the mix of sales across 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 2020, particularly in Florida, has further reduced the consolidated impact. The Company has not deferred any costs for future recovery as a result of the pandemic. Capital project delays and supply chain disruptions have also 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 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. 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. There have been no significant customer defaults as a result of bankruptcies with many accounts being secured by deposits. As of December 31, 2020, adjustments to the allowance for credit losses have increased but 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 working 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, timing and effectiveness of vaccinations, further potential government actions and future economic activity and energy usage. In Q1 2020, the Company updated its principal risks to reflect this uncertainty. For this risk update, refer to the "Risk Management and Financial Instruments" section of this document and note 27 in the consolidated financial statements. The Company has disclosed the impact of this uncertainty on its accounting estimates used in the preparation of the financial statements. For further detail, refer to the "Critical Accounting Estimates" section of this document, and the "Use of Management Estimates" section of note 1 in the consolidated financial statements.

Potential future impacts of COVID-19 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 below, by segment, for affiliate specific impacts. These segment outlooks are based on the information currently available, however, the total impact of COVID-19 is unknown at this time.

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. 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. For further detail, refer to the "Liquidity and Capital Resources" section of this document.

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 has approximately $10 billion USD of assets and approximately 792,500 customers at December 31, 2020. Tampa Electric owns 5,790 MW of generating capacity, of which 78 per cent is natural gas-fired, 12 per cent is coal and 10 per cent is solar. Tampa Electric owns 2,165 kilometres of transmission facilities and 19,250 kilometres of distribution facilities.

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

Due to continued growth in rate base, Tampa Electric anticipates earning near or below the bottom of the allowed ROE range in 2021. Tampa Electric sales volumes are expected to be lower than in 2020, which benefited from weather that was warmer than in recent years. As a result, Tampa Electric anticipates earnings to be slightly lower than in 2020. Tampa Electric expects customer growth rates in 2021 to be consistent with 2020, reflective of current expected economic growth in Florida.

On February 1, 2021, Tampa Electric notified the FPSC of its intent to seek a base rate increase, reflecting incremental revenue requirements of approximately $280 million USD to $295 million USD, effective January 2022. Tampa Electric's proposed rates include recovery for the costs of the first phase of the Big Bend modernization project, 225 MW of utility-scale solar projects, the advanced metering infrastructure ("AMI") investment, and accelerated recovery of the remaining net book value of retiring assets. Tampa Electric also intends to seek approval for Generation Base Rate Adjustments of $130 million USD to recover the costs of the second phase of the Big Bend modernization project and additional utility-scale solar projects in subsequent years. These filing amounts are estimates until Tampa Electric completes and files its detailed case. Tampa Electric expects to file its detailed case on or after April 2, 2021, and a decision by the FPSC is expected by the end of 2021.

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 began 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.

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. As of December 31, 2020, Tampa Electric has invested approximately $213 million USD in these projects. AFUDC is being earned on these projects during construction. For further detail, refer to the "Developments" section.

Tampa Electric expects to invest approximately $850 million USD through 2023 to modernize the Big Bend Power Station, of which approximately $526 million USD has been invested through December 31, 2020. The modernization project will repower Big Bend Unit 1 with natural gas combined-cycle technology and eliminate coal as this unit's fuel. On June 1, 2020, Tampa Electric retired the Unit 1 components that will not be used in the modernized plant. In addition, Tampa Electric plans to retire Big Bend Unit 2 in 2021. In accordance with Tampa Electric's 2017 settlement agreement, Tampa Electric was not required to request an asset recovery schedule for retired assets until the next depreciation study. On December 30, 2020, Tampa Electric filed a depreciation and dismantlement study and request for capital recovery schedules with the FPSC.

Tampa Electric plans to retire Big Bend Unit 3 in 2023 as it is in the best interest of customers from economic, environmental risk and operational perspectives. Similar to the retirement plan for Unit 1 and Unit 2, Tampa Electric will continue to account for its existing investment in Unit 3 in electric utility plant and depreciate the assets using the current depreciation rates until the FPSC approves Tampa Electric's next depreciation and dismantlement study.

In 2021, capital investment in the Florida Electric Utility segment is expected to be approximately $1.2 billion USD (2020 - $1.0 billion USD), including AFUDC. Capital projects include solar investments, continuation of the modernization of the Big Bend Power Station, storm hardening investments and AMI.

Canadian Electric Utilities

Canadian Electric Utilities includes NSPI and ENL. NSPI is 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. ENL is 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.

NSPI

With approximately $5.5 billion of assets and approximately 529,000 customers, NSPI owns 2,433 MW of generating capacity, of which approximately 43 per cent is coal-fired; 28 per cent is natural gas and/or oil; 20 per cent is hydro and wind; 7 per cent is petcoke and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP") which own 456 MW of capacity. NSPI owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities.

Energy from renewable sources will increase upon delivery of the Nova Scotia block ("NS Block") of electricity transmitted through the Maritime Link from the Muskrat Falls hydroelectric project. The NS Block will provide NSPI with approximately 900 GWh of energy annually for 35 years. In addition, for the first 5 years of the NS Block, NSPI is also entitled to receive approximately 240 GWh of additional energy from the Supplemental Energy Block transmitted through the Maritime Link. NSPI has the option of purchasing additional market-priced energy from Nalcor through the Energy Access Agreement. Nalcor is obligated to offer NSPI a minimum average of 1.2 TWh of energy annually pursuant to this agreement. Delivery of the NS Block is anticipated to commence in 2021.

NSPI's approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40 per cent. NSPI anticipates earning within its allowed ROE range in 2021 and expects rate base and earnings to be higher than 2020. The impact of the COVID-19 pandemic on Nova's Scotia's economy and warmer than normal weather adversely affected NSPI's sales volumes and earnings in 2020. Assuming normal weather and a modest economic recovery in 2021, NSPI expects sales volumes to be higher than 2020. Depending on the duration and severity of the COVID-19 pandemic and the pace and strength of economic recovery, NSPI may continue to experience adverse impacts on sales volumes in 2021.

NSPI is currently operating under a three-year fuel stability plan which results in an average annual overall rate increase of 1.5 per cent to recover fuel costs for the period of 2020 through 2022. These rates include recovery of Maritime Link costs (discussed below in the "ENL, NSPML" section).

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.

The Government of Canada has laws and regulations that would compel the closure of coal plants before the end of their economic life and at the latest by 2030. The Canada-Nova Scotia Equivalency Agreement allows NSPI to achieve compliance with federal greenhouse gas ("GHG") emissions regulations. The current Equivalency Agreement, which must be renewed in five year increments, provides equivalency for the 2020-2024 period and outlines the framework for equivalency for the 2025 to 2040 period. At December 31, 2020, NSPI was in compliance with provincial requirements.

On November 19, 2020, the Government of Canada introduced Bill C-12, "Canadian Net-Zero Emissions Accountability Act", which requires national targets be set for the reduction of GHG emissions in Canada, with the objective of attaining net-zero emissions by 2050. NSPI continues to work with the federal government on measures to address their carbon reduction goals.

On December 11, 2020, the federal government announced plans to increase the carbon tax in Canada starting in 2023, increasing $15 per tonne annually and reaching $170 per tonne by 2030, under the Greenhouse Gas Pollution Pricing Act ("GGPPA"). The GGPPA is a federal back stop for a price on carbon. As Nova Scotia prices carbon through the Nova Scotia Cap-and-Trade Program Regulations, it is NSPI's expectation that Nova Scotia's regulations will be considered equivalent to the proposed carbon tax under the GGPPA. NSPI will continue to work with the provincial government to understand their approach to changes to the Cap-and-Trade Program after 2022 to address the federal government's plans.

NSPI will receive its 2021 granted emissions allowances under the Nova Scotia Cap-and-Trade Program Regulations in Q1 2021. These allowances will be used in 2021 or allocated within the initial four-year compliance period that ends in 2022. 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 GHG emitting sources of energy has resulted in NSPI making significant investments in renewable energy sources, including energy from the Maritime Link, and purchasing renewable energy from IPP's.

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 did 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 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 period. NSPI expects to achieve this alternative compliance standard.

In 2021, NSPI expects to invest approximately $370 million (2020 - $316 million), including AFUDC, primarily in capital projects to support system reliability and hydroelectric infrastructure renewal investments.

ENL

NSPML

Through its subsidiary, NSPML, ENL has invested $1.9 billion of equity, debt and working capital, including $209 million of AFUDC, in the development of the Maritime Link Project. This investment consists of $546 million in equity, comprised of $443 million in equity contribution and $103 million of accumulated retained earnings, with the remaining being funded with working capital and debt. The project debt has been guaranteed by the Government of Canada.

The Maritime Link assets entered service on January 15, 2018 and provides for the transmission of energy and improved reliability and ancillary benefits, supporting the efficiency and reliability of both provinces. The Maritime Link will transmit at greater capacity when the Lower Churchill project is complete.

Equity earnings 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.

On December 16, 2020, the UARB approved NSPML's 2021 interim cost assessment for recovery from NSPI of Maritime Link costs of approximately $172 million subject to a holdback of $10 million on similar terms as previously approved by the UARB and a potential long-term deferral of up to $23 million in depreciation expense dependent upon the timing of commencement of the NS Block. Recovery of this interim assessment began on January 1, 2021. NSPML expects to file a final cost assessment with the UARB upon commencement of the NS Block of energy from Muskrat Falls which is expected to take place in 2021.

In 2021, NSPML expects to invest approximately $15 million (2020 - $7 million) in capital.

LIL

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

Equity earnings from the LIL investment are based upon the value of the equity investment and the approved ROE. Emera's current equity investment is $628 million, comprised of $410 million in equity contribution and $218 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.

Equity earnings from NSPML and LIL are expected to be higher in 2021, compared to 2020. Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Consolidated Balance Sheets.

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. ECI's regulated utilities include vertically integrated regulated electric utilities of BLPC on the island of Barbados, GBPC on Grand Bahama Island, a 51.9 per cent interest in Domlec on the island of Dominica and a 19.5 per cent interest in Lucelec on the island of St. Lucia which is accounted for on the equity basis.

On March 24, 2020, Emera completed the sale of Emera Maine which is included in the Other Electric Utilities segment for Q1 2020 and all of 2019. For further detail, refer to the "Significant Items Affecting Earnings" and "Developments" sections.

BLPC

With approximately $466 million USD of assets and approximately 131,000 customers, BLPC owns 266 MW of generating capacity, of which 96 per cent is oil-fired and four per cent is solar. The utility has an additional 12 MW of capacity from rental units through March 31, 2021. BLPC owns approximately 184 kilometres of transmission facilities and 2,800 kilometres of distribution facilities. BLPC's approved regulated return on rate base is 10.0 per cent.

GBPC

With approximately $320 million USD of assets and approximately 19,000 customers, GBPC owns 98 MW of oil-fired generation, approximately 138 kilometres of transmission facilities and 860 kilometres of distribution facilities. The utility has an additional 18 MW of capacity from rental units which are expected to be returned in the first half of 2021, when the generation units damaged by Hurricane Dorian are returned to service. In January 2021, the GBPA approved GBPC's regulated return on rate base of 8.37 per cent for 2021 (2020 - 8.34 per cent).

Domlec

Domlec serves approximately 34,000 customers. Domlec owns 26.7 MW of generating capacity, of which 75 per cent is oil-fired and 25 per cent is hydro. Domlec owns approximately 475 kilometres of transmission facilities and 709 kilometres of distribution facilities. Domlec's approved regulated return on rate base is 15.0 per cent.

Other Electric Utilities Outlook

Other Electric Utilities' earnings are expected to increase over the prior year due to higher earnings in 2021 from the Caribbean utilities, partially offset by lower earnings contribution due to the sale of Emera Maine in early 2020. Earnings are expected to increase in 2021 as local economies begin to recover from the impacts of COVID-19 and continued recovery from Hurricane Dorian at GBPC.

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

BLPC operates pursuant to a franchise to generate, transmit and distribute electricity on the island until 2028. In 2019, the Government of Barbados passed legislation amending the number of licenses required for the supply of electricity from a single integrated license which currently exists to multiple licenses for Generation, Transmission and Distribution, Storage, Dispatch and Sales. BLPC is negotiating the terms of the new licenses under the amended legislation.

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. These costs were recorded as a regulatory asset and recovery began January 1, 2021.

In 2021, capital investment in the Other Electric Utilities segment is expected to be approximately $165 million USD (2020 – $111 million USD including $14 million USD invested in Emera Maine projects). Forecasted capital investment is primarily in more efficient and cleaner sources of generation, including renewables and battery storage. BLPC expects to complete installation of a 33MW diesel engine in 2021. This 33 MW plant is expected to increase efficiency and bridge BLPC's transition to increased renewable sources of generation.

Gas Utilities and Infrastructure

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

Peoples Gas System

With approximately $1.6 billion USD of assets and approximately 426,000 customers, the PGS system includes approximately 22,200 kilometres of natural gas mains and 12,600 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2.1 billion therms in 2020.

For 2020, the approved ROE range for PGS was 9.25 per cent to 11.75 per cent, based on an allowed equity capital structure of 54.7 per cent. An ROE of 10.75 per cent was used for the calculation of return on investments for clauses. Beginning in 2021, the approved ROE range is 8.9 per cent to 11.0 per cent, based on an allowed equity capital structure of 54.7 per cent and an ROE of 9.9 per cent will be used for the calculation of return on investments for clauses. See below for further detail.

New Mexico Gas Company, Inc.

With approximately $1.5 billion USD of assets and approximately 540,000 customers, NMGC serves approximately 60 per cent of New Mexico's population in 23 of the state's 33 counties. NMGC's system includes approximately 2,443 kilometres of transmission pipelines and 17,243 kilometres of distribution pipelines. Annual natural gas throughput was approximately 948 million therms in 2020.

For 2020, the approved ROE for NMGC was 9.1 per cent, on an allowed equity capital structure of 52 per cent. New rates became effective August 2019 and were phased in over two years resulting in an annual revenue increase of approximately $3 million USD. In addition, NMGC's weather mechanism became effective October 2019. Beginning in 2021, the approved ROE is 9.375 per cent on an allowed equity capital structure of 52 per cent. See below for further detail.

Gas Utilities and Infrastructure Outlook

Gas Utilities and Infrastructure earnings are anticipated to be higher in 2021 than 2020 primarily due to rate base growth to expand the distribution system and to continue to reliably serve customers.

PGS anticipates earning within its allowed ROE range in 2021 and expects rate base and earnings to be higher than in 2020. PGS expects customer growth in 2021 to be higher than Florida's population growth rates, reflecting expectations of continued strong housing demand in Florida and commercial activity trending back towards normal levels. Assuming normal weather, PGS sales volumes are expected to increase above customer growth, as the COVID-19 pandemic impact on 2021 commercial energy sales is expected to be less than 2020. In January 2021, a base rate increase went into effect in accordance with the FPSC approved rate case settlement and is expected to result in a $34 million USD revenue increase.

PGS was permitted to initiate a general base rate proceeding during 2020, provided the new rates do not become effective before January 1, 2021. On June 8, 2020, PGS filed a petition for an increase in rates and service charges effective January 2021. On November 19, 2020, the FPSC approved a settlement agreement filed by PGS. The settlement agreement allows for an increase in base rates by $58 million USD annually effective January 2021, which is a $34 million USD increase in revenue and $24 million USD increase of revenues previously recovered through the cast iron and bare steel replacement rider. This settlement agreement includes an allowed regulatory ROE range of 8.9 per cent to 11.0 per cent with a 9.9 per cent midpoint. It provides PGS 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 that are 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 were to fall below 8.9 per cent before that time with an allowed equity in the capital structure of 54.7 per cent from investor sources of capital. The settlement agreement provides for the deferral of income taxes as a result of changes in tax laws. The changes would be reflected as a regulatory asset or liability and either result in an increase or a decrease in customer rates through a subsequent regulatory process.

NMGC anticipates earning at or near its authorized ROE in 2021 and expects rate base to be higher than 2020. NMGC expects customer growth rates to be consistent with historical trends.

NMGC filed a rate case in December 2019. NMGC reached an unopposed stipulated settlement of the case which was approved by the NMPRC in December 2020. The new rates reflect the recovery of capital investment in pipelines and related infrastructure and results in an increase in revenue of approximately $5 million USD annually effective January 2021. The stipulated settlement agreement includes an allowed regulatory ROE of 9.375 per cent on an allowed equity capital structure of 52 per cent. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2022, unless new federal tax rates are enacted, in which case NMGC can file for new rates to be effective earlier than January 1, 2023.

In 2018, SeaCoast executed an agreement with Seminole Electric Cooperative, Inc. ("Seminole") to provide long-term firm gas transportation service to Seminole's new gas-fired generating facility being constructed in Putnam County, Florida. SeaCoast is constructing and will operate a 21-mile, 30-inch pipeline lateral that will be treated as a sales-type lease for accounting purposes. The lease of the pipeline lateral to Seminole is anticipated to commence in January 2022. The capital investment is projected to be approximately $100 million USD, with the majority of the project investment completed through 2020. SeaCoast also jointly developed the 26.5 mile, 16-inch Callahan Pipeline with Peninsula Pipeline Co., an affiliate of Florida Public Utilities. The SeaCoast pipeline went into service in Q4 2020 providing long-term firm gas transportation service to PGS in the northeast Florida area with 2021 being the first full year of operation. SeaCoast's portion of the capital investment in the Callahan Pipeline was approximately $30 million USD.

In 2021, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $425 million USD (2020 - $553 million USD), including AFUDC. PGS will make investments to expand its system and support customer growth. NMGC completed the Santa Fe Mainline Looping project in January 2021 and will continue to invest in system improvements.

Other

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

Business operations in Other include Emera Energy, which consists of:

- Emera Energy Services ("EES"), a wholly owned physical energy marketing and trading business; 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.

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

Earnings from EES are generally dependent on market conditions. In particular, volatility in electricity and natural gas markets, which can be influenced by weather, local supply constraints and other supply and demand factors, can provide higher levels of margin opportunity. The business is seasonal, with Q1 and Q4 usually providing the greatest opportunity for earnings. EES 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. The COVID-19 related economic slowdown did not have a material impact on EES earnings in 2020. The pandemic remains a challenge to the overall economy but is expected to continue to have limited impact on EES operations unless circumstances deteriorate significantly.

Absent the gain on the TGH award in 2020, the adjusted net loss from the Other segment is expected to be lower in 2021, based on EES returning to its normal earnings range.

In 2021, capital investment in the Other segment is expected to be approximately $2 million (2020 - $3 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

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

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Receivables and other assets (current and long-term)	**(226)**	Decreased due to the refund of corporate alternative minimum tax credit ("AMT") carryforwards, lower gas transportation assets at Emera Energy, a refund of prior year income taxes receivable at NSPI, cash collateral positions on derivative instruments at NSPI and lower commodity prices at Emera Energy.
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	**1,368**	Increased due to capital additions at Tampa Electric, PGS and NSPI, partially offset by the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Goodwill	**(115)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**(371)**	Decreased due to net repayments on committed credit facilities at TECO Finance, Emera and NSPI, repayment of long-term debt at TECO Finance, and the effect of a stronger CAD on the translation of Emera's foreign affiliates. This was partially offset by a net issuance on committed credit facilities at Tampa Electric and PGS and issuance of long-term debt at NSPI
Deferred income tax liabilities, net of deferred income tax assets	**321**	Increased due to net utilization of tax loss carryforwards primarily related to the sale of Emera Maine, and tax deductions in excess of accounting depreciation related to property, plant and equipment. 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 and the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Regulatory liabilities (current and long-term)	**(220)**	Decreased due to changes in the fuel adjustment mechanism deferral and derivative instrument deferrals at NSPI, decreased deferred income tax regulatory liabilities primarily due to amortization of excess deferred income taxes related to US Tax Reform at Tampa Electric, PGS and NMGC, and the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Common stock	**489**	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	**(174)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Retained earnings	**322**	Increased due to the gain on sale of Emera Maine and net income in excess of dividends paid

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 was effective November 16, 2020. Emera also reaffirmed its four to five per cent annual dividend growth rate target through 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 were 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

Board of Directors

Effective February 12, 2021, Karen Sheriff joined the Emera Board of Directors. Most recently, Ms. Sheriff served as President and Chief Executive Officer of Q9 Networks Inc., a data centre services provider. Before that, she was President and Chief Executive Officer of Bell Aliant, Inc., a telecommunications company.

Executive

On February 9, 2021, Emera announced that Archie Collins was appointed President and Chief Executive Officer of Tampa Electric Company effective May 3, 2021. Until that time, Mr. Collins will serve as President and Chief Operating Officer and was most recently the Chief Operating Officer of Tampa Electric Company. Mr. Collins will succeed Nancy Tower who is retiring in June 2021.

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)	4.54		251
Issued for cash under Purchase Plans at market rate	3.99		219
Discount on shares purchased under Dividend Reinvestment Plan	-		(4)
Options exercised under senior management stock option plan	0.42		20
Employee Share Purchase Plan	-		3
Balance, December 31, 2020	**251.43**	**$**	**6,705**

(1) As at December 31, 2019, 1,768,120 common shares were issued under Emera's at-the-market program ("ATM program") at an average price of $56.56 per share for gross proceeds of $100 million ($99 million net of issuance costs).

(2) In Q4 2020, 1,835,422 common shares were issued under Emera's ATM program at an average price of $55.19 per share for gross proceeds of $102 million ($100 million net of issuance costs). For the year ended December 31, 2020, 4,544,025 common shares were issued under Emera's ATM program at an average price of $56.04 per share for gross proceeds of $255 million ($251 million net of issuance costs). As at December 31, 2020, an aggregate gross sales limit of $245 million remains available for issuance under the ATM program.

As at February 9, 2021, the amount of issued and outstanding common shares was 251.6 million.

The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended December 31, 2020 was 251.3 million (2019 – 242.9 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2020 was 247.8 million (2019 – 239.9 million).

At-The-Market Equity Program

On November 17, 2020, Emera filed an amendment to its July 11, 2019 prospectus supplement which established its ATM program. This amendment reflected changes in securities regulations related to ATM programs which were effective August 31, 2020. The amendment includes removal of the daily trading limit which previously provided that the number of shares sold could not exceed 25 per cent of the daily trading volume of the shares.

Cumulative Preferred Stock

For details regarding cumulative preferred stock, refer to note 28 in Emera’s 2020 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 ended 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 December 31		Year ended December 31	
	2020	2019	**2020**	2019
Operating revenues – regulated electric	**$ 468**	$ 473	**$ 1,849**	$ 1,965
Regulated fuel for generation and purchased power	**$ 127**	$ 143	**$ 428**	$ 582
Contribution to consolidated net income	**$ 76**	$ 61	**$ 372**	$ 316
Contribution to consolidated net income – CAD	**$ 101**	$ 80	**$ 501**	$ 419
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.40**	$ 0.33	**$ 2.02**	$ 1.75
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.31**	$ 1.32	**$ 1.34**	$ 1.33
EBITDA	**$ 201**	$ 187	**$ 891**	$ 828
EBITDA – CAD	**$ 263**	$ 245	**$ 1,196**	$ 1,098

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2019	**$ 61**	**$ 316**
Decreased operating revenues - see Operating Revenues - Regulated Electric below	(5)	(116)
Decreased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	16	154
Increased depreciation due to increased property, plant and equipment	(4)	(19)
Decreased amortization expenses resulting from a credit to accumulated amortization reserve surplus for intangible software assets as approved by the regulator	4	16
Increased AFUDC earnings due to the Big Bend Power Station modernization and solar projects	5	15
Other	(1)	6
Contribution to consolidated net income – 2020	**$ 76**	**$ 372**

Florida Electric Utility's CAD contribution to consolidated net income increased $21 million in Q4 2020, compared to Q4 2019. For the year ended December 31, 2020, Florida Electric Utility's CAD contribution to consolidated net income increased $82 million, compared to 2019. The increase in both periods was due to increased base revenues, as described below, and higher AFUDC earnings as a result of the Big Bend Power Station 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 related to COVID-19, warmer weather than in the prior year and customer growth.

The impact of the change in the foreign exchange rate decreased CAD earnings for the quarter by $1 million and increased CAD earnings at year ended December 31, 2020 by $6 million.

Operating Revenues – Regulated Electric

Electric revenues decreased $5 million to $468 million in Q4 2020, compared to $473 million in Q4 2019. For the year ended December 31, 2020, electric revenues decreased $116 million to $1,849 million, from $1,965 million in 2019. The decreases in both periods were due to lower clause revenues as a result of a decrease in fuel cost, partially offset by the in-service of solar generation projects, predominately warmer weather than in prior year, a greater mix of residential sales related to COVID-19 and customer growth.

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

Q4 Electric Revenues
millions of US dollars

		2020		2019
Residential	**$**	**256**	$	254
Commercial		**132**		141
Industrial		**34**		39
Other (1)		**46**		39
Total	**$**	**468**	$	473

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

Annual Electric Revenues
millions of US dollars

		2020		2019
Residential	**$**	**1,018**	$	1,046
Commercial		**506**		562
Industrial		**133**		156
Other (1)		**192**		201
Total	**$**	**1,849**	$	1,965

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

Q4 Electric Sales Volumes
Gigawatt hours ("GWh")

	2020	2019
Residential	**2,465**	2,303
Commercial	**1,526**	1,536
Industrial	**460**	501
Other	**515**	579
Total	**4,966**	4,919

Annual Electric Sales Volumes
GWh

	2020	2019
Residential	**10,122**	9,584
Commercial	**6,058**	6,240
Industrial	**1,891**	2,021
Other	**1,958**	2,094
Total	**20,029**	19,939

Regulated Fuel for Generation and Purchased Power

Tampa Electric is required to maintain a generating capacity greater than firm peak demand. The total Tampa Electric-owned generation capacity is 5,790 MW. Tampa Electric meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

Regulated fuel for generation and purchased power decreased $16 million to $127 million in Q4 2020, compared to $143 million in Q4 2019. For the year ended December 31, 2020, regulated fuel for generation and purchased power decreased $154 million to $428 million, compared to $582 million in 2019. The decrease in both periods was due to lower natural gas prices and increased solar generation.

Q4 Production Volumes
GWh

	2020	2019
Natural gas	**3,616**	4,075
Coal	**344**	323
Solar	**232**	169
Purchased power	**747**	210
Total	**4,939**	4,777

Annual Production Volumes
GWh

	2020	2019
Natural gas	**16,523**	17,514
Coal	**904**	1,214
Solar	**1,120**	756
Purchased power	**2,513**	1,290
Total	**21,060**	20,774

Q4 Average Fuel Costs

US dollars	2020	2019
Dollars per Megawatt hour ("MWh")	**$ 26**	$ 30

Annual Average Fuel

US dollars	2020	2019
Dollars per MWh	**$ 20**	$ 28

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

Average fuel cost per MWh decreased in Q4 2020 and for the year ended December 31, 2020, compared to 2019, due to lower natural gas prices and increased use of solar generation which has no fuel cost.

Regulatory Recovery Mechanisms

Tampa Electric is regulated by FPSC. Tampa Electric is also subject to regulation by the FERC. The FPSC sets rates at a level that allows utilities such as Tampa Electric to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital. Base rates are determined in FPSC rate setting hearings which occur at the initiative of Tampa Electric, the FPSC or other interested parties.

Solar Base Rate Adjustments Included in Base Rates

As of December 31, 2020, Tampa Electric has invested $820 million USD in 600 MW of utility-scale solar photovoltaic projects, which are recoverable through FPSC-approved solar base rate adjustments ("SoBRAs"). Tampa Electric expects to invest an additional $30 million USD in these projects through 2021. AFUDC is being earned on these projects during construction. The FPSC has approved SoBRAs representing a total of 600 MW or $104 million USD annually in estimated revenue requirements for in-service projects.

The true-up filing for SoBRAs tranche 1 and 2 revenue requirement estimates that were included in base rates as of September 2018 and January 2019, respectively, was submitted on April 30, 2020, and the FPSC approved the amount on August 18, 2020. A $5 million USD true-up was returned to customers in 2020. The true-ups for SoBRA tranches 3 and 4 will be filed in 2021 and 2022, respectively.

Other Cost Recovery

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

Storm Protection Plan Cost Recovery Clause
Tampa Electric has a Storm Protection Plan cost recovery clause allowing recovery of prudent transmission and distribution storm hardening costs for incremental activities not already included in base rates as outlined in the programs in its approved Storm Protection Plan. Differences between the prudently incurred clause-recoverable costs and amounts recovered from customers through electricity rates in a year are deferred and recovered from or returned to customers in a subsequent year.

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

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

Canadian Electric Utilities

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Operating revenues – regulated electric	**$ 377**	$ 364	**$ 1,494**	$ 1,430
Regulated fuel for generation and purchased power (1)	**$ 219**	$ 183	**$ 721**	$ 663
Income from equity investments	**$ 21**	$ 23	**$ 96**	$ 91
Contribution to consolidated net income	**$ 57**	$ 58	**$ 221**	$ 229
Contribution to consolidated earnings per common share – basic	**$ 0.23**	$ 0.24	**$ 0.89**	$ 0.95
EBITDA	**$ 157**	$ 151	**$ 614**	$ 592

(1) Regulated fuel for generation and purchased power includes NSPI's Fuel Adjustment Mechanism ("FAM") and fixed cost deferrals on the Consolidated Statements of Income, however it is excluded in the segment overview.

Canadian Electric Utilities' contribution to consolidated net income is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
NSPI	**$ 36**	$ 35	**$ 125**	$ 138
Equity investment in LIL	**12**	12	**49**	45
Equity investment in NSPML	**9**	11	**47**	46
Contribution to consolidated net income	**$ 57**	$ 58	**$ 221**	$ 229

Net Income

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

For the millions of Canadian dollars		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2019	**$**	**58**	**$**	**229**
Increased operating revenues - see Operating Revenues – Regulated Electric below		13		64
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below		(36)		(58)
Decreased FAM expense in the quarter primarily due to the refund of prior years' over-recovery of fuel costs, partially offset by increased recoveries of current period fuel costs. Year-over-year increase in FAM expense due to over recoveries of current period fuel costs and the prior year recovery of the reduced Maritime Link assessment returned to customers in subsequent years. This was partially offset by the refund of customers of prior years' over-recovery of fuel costs.		12		(28)
Decreased OM&G expense quarter-over-quarter primarily due to lower labour costs, storm restoration costs, power generation and vegetation management costs and decreased demand side management ("DSM") expense. Year-over-year these decreases were partially offset by lower overhead allocated to property, plant and equipment, and COVID-19 pandemic response costs.		14		31
Increased year-over-year due to increased equity earnings from the LIL		(1)		5
Increased income taxes primarily due to a reduction in the non-capital loss carryback as a result of lower tax deductions in excess of accounting depreciation related to property, plant and equipment and the tax benefits of capital investment related to post-tropical storm Dorian in 2019.		(5)		(27)
Other		2		5
Contribution to consolidated net income – 2020	**$**	**57**	**$**	**221**

Canadian Electric Utilities' contribution to consolidated net income decreased $1 million to $57 million in Q4 2020, compared to $58 million for the same period in 2019. For the year ended December 31, 2020 Canadian Electric Utilities' contribution to consolidated net income decreased $8 million to $221 million compared to $229 million in 2019. The decrease in both periods was due to higher income tax expense, warmer weather than prior year, and lower commercial sales related to COVID-19, partially offset by decreased OM&G expense and increased mix of residential sales related to COVID-19 at NSPI.

The timing of regulatory deferrals causes quarterly earnings volatility, while full year results are more predictable.

NSPI

Operating Revenues – Regulated Electric

Operating revenues increased $13 million to $377 million in Q4 2020, compared to $364 million in Q4 2019. For the year ended December 31, 2020, operating revenues increased $64 million to $1,494 million, compared to $1,430 million in 2019. The increase in both periods was primarily due to a higher Maritime Link assessment included in revenue compared to 2019, increased fuel-related pricing, and higher residential sales volumes related to COVID-19. This was partially offset by decreased sales volumes due to warmer weather than prior year and decreased commercial sales volumes primarily due to the impact of the COVID-19 pandemic. Quarter-over-quarter was also impacted by increased industrial sales volumes. Year-over-year was also partially offset by decreased other sales volumes.

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

Q4 Electric Revenues
millions of Canadian dollars

		2020		2019
Residential	**$**	**199**	$	194
Commercial		**102**		102
Industrial		**60**		50
Other		**7**		10
Total	**$**	**368**	$	356

Annual Electric Revenues
millions of Canadian dollars

		2020		2019
Residential	**$**	**806**	$	746
Commercial		**405**		400
Industrial		**224**		210
Other		**31**		45
Total	**$**	**1,466**	$	1,401

Q4 Electric Sales Volumes
GWh

	2020	2019
Residential	**1,159**	1,210
Commercial	**712**	763
Industrial	**629**	571
Other	**36**	78
Total	**2,536**	2,622

Annual Electric Sales Volumes
GWh

	2020	2019
Residential	**4,652**	4,664
Commercial	**2,850**	3,068
Industrial	**2,341**	2,388
Other	**185**	350
Total	**10,028**	10,470

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $36 million to $219 million in Q4 2020, compared to $183 million in Q4 2019. For the year ended December 31, 2020, regulated fuel for generation and purchased power increased $58 million to $721 million, compared to $663 million in 2019. Changes in both periods were primarily due to higher Maritime Link assessment costs in 2020, changes in generation mix, and increased commodity prices, partially offset by decreased sales volumes.

Q4 Production Volumes
GWh

	2020	2019
Coal	**1,249**	1,398
Natural gas	**351**	322
Oil and petcoke	**174**	149
Purchased power – other	**235**	139
Total non-renewables	**2,009**	2,008
Purchased power – IPP	**353**	371
Wind and hydro	**215**	306
Purchased power – Community Feed-in Tariff program ("COMFIT")	**156**	163
Biomass	**21**	14
Total renewables	**745**	854
Total production volumes	**2,754**	2,862

Annual Production Volumes
GWh

	2020	2019
Coal	**4,342**	4,949
Natural gas	**1,872**	1,369
Oil and petcoke	**967**	981
Purchased power – other	**663**	786
Total non-renewables	**7,844**	8,085
Purchased power – IPP	**1,250**	1,202
Wind and hydro	**1,001**	1,289
Purchased power – COMFIT	**558**	552
Biomass	**106**	73
Total renewables	**2,915**	3,116
Total production volumes	**10,759**	11,201

Q4 Average Fuel Costs

		2020		2019
Dollars per MWh	**$**	**80**	$	64

Annual Average Fuel Costs

		2020		2019
Dollars per MWh	**$**	**67**	$	59

Average fuel cost per MWh increased in Q4 2020 compared to Q4 2019 due to higher Maritime Link assessment costs in 2020 and increased commodity pricing. For the year ended December 31, 2020 compared to the same period in 2019, fuel costs increased due to 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. This was partially offset by lower generation from solid fuel.

NSPI's FAM regulatory liability balance decreased $94 million from $115 million at December 31, 2019 to $21 million at December 31, 2020, primarily due to the refund of prior years' over-recovery of fuel costs and reduced 2019 Maritime Link assessment refunded to customers in 2020. This was partially offset by over-recovery of current-period fuel costs.

NSPI's fuel costs are affected by commodity prices and generation mix, which is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on stream first after renewable energy from IPPs including COMFIT participants, for which NSPI has power purchase agreements in place.

NSPI-owned hydro and wind have no fuel cost component. After hydro and wind, historically, petcoke and coal have the lowest per unit fuel cost, followed by natural gas. Oil, biomass and purchased power have the next lowest fuel cost, depending on the relative pricing of each. Generation mix may also be affected by plant outages, availability of renewable generation, plant performance and compliance with environmental standards and regulations.

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

Regulatory Recovery Mechanisms

NSPI

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

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

NSPI has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel costs from customers through fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability.

As part of the three-year fuel stability plan, electricity rates have been set to include the $145 million approved Maritime Link assessment for 2020 and amounts of $164 million and $162 million for 2021 and 2022, respectively. On December 16, 2020, the UARB approved NSPML's 2021 interim cost assessment recovery from NSPI of Maritime Link costs of approximately $172 million subject to a holdback of $10 million on similar terms as previously approved by the UARB and a potential long-term deferral of up to $23 million in depreciation expense dependent upon the timing of commencement of the NS Block. Refer to the NSPML section below for further details. Any difference between the amounts included in the fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

Other Electric Utilities

All amounts are reported in USD, unless otherwise stated.

On March 24, 2020, Emera completed the sale of Emera Maine. For further detail, refer to the "Significant Items Affecting Earnings" and "Developments" sections.

For the millions of US dollars (except per share amounts)		Three months ended December 31 **2020**		2019		Year ended December 31 **2020**		2019
Operating revenues – regulated electric	**$**	**79**	$	140	**$**	**354**	$	561
Regulated fuel for generation and purchased power (1)	**$**	**35**	$	58	**$**	**145**	$	216
Adjusted contribution to consolidated net income	**$**	**5**	$	10	**$**	**24**	$	57
Adjusted contribution to consolidated net income – CAD	**$**	**8**	$	14	**$**	**33**	$	76
Impairment charges	**$**	**-**	$	(26)	**$**	**-**	$	(26)
After-tax equity securities MTM gain	**$**	**2**	$	-	**$**	**2**	$	2
Contribution to consolidated net income	**$**	**7**	$	(16)	**$**	**26**	$	33
Contribution to consolidated net income – CAD	**$**	**10**	$	(19)	**$**	**35**	$	45
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$**	**0.03**	$	0.06	**$**	**0.13**	$	0.32
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.04**	$	(0.08)	**$**	**0.14**	$	0.19
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.28**	$	1.32	**$**	**1.34**	$	1.33
Adjusted EBITDA	**$**	**19**	$	38	**$**	**96**	$	187
Adjusted EBITDA – CAD	**$**	**27**	$	52	**$**	**129**	$	249

(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 December 31 **2020**		2019		Year ended December 31 **2020**		2019
ECI	**$**	**5**	$	3	**$**	**20**	$	22
Emera Maine		**-**		7		**4**		35
Adjusted contribution to consolidated net income	**$**	**5**	$	10	**$**	**24**	$	57

Net Income

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

For the millions of US dollars		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2019	**$**	**(16)**	**$**	**33**
Operating revenues - see Operating Revenues - Regulated Electric below		(12)		(48)
Regulated fuel for generation - see Regulated Fuel for Generation and Purchased Power below		13		41
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
GBPC impairment charge in 2019		26		26
Impact on earnings of sale of Emera Maine, net of tax		(7)		(31)
Other		3		(2)
Contribution to consolidated net income – 2020	**$**	**7**	**$**	**26**

In Q4 2019, the Company recognized a non-cash impairment charge, primarily related to goodwill, of $26 million USD due to a decrease in expected future cash flows resulting from the impacts of Hurricane Dorian storm recovery and changes in the anticipated long term regulated capital structure of GBPC. No impairment charge related to GBPC was recognized in 2020.

Excluding the change in MTM, the 2019 impairment charges at GBPC and the sale of Emera Maine, Other Electric Utilities CAD’s contribution to consolidated net income increased $3 million quarter-over-quarter and decreased $2 million year-over-year. ECI’s contribution in Q4 2020 increased due to the continued recovery from Hurricane Dorian. ECI’s contribution for the year decreased due to lower commercial sales, partially offset by increased sales to residential customers due to the impact of the COVID-19 pandemic, and the impact from Hurricane Dorian at GBPC. 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 and year ended December 31, 2020.

Operating Revenues – Regulated Electric

Operating revenues decreased $61 million to $79 million in Q4 2020, compared to $140 million in Q4 2019. For the year ended December 31, 2020, operating revenues decreased $207 million to $354 million compared to $561 million 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 oil prices, lower commercial sales partially offset by increased sales to residential customers due to the impact of the COVID-19 pandemic, and the impacts of Hurricane Dorian at GBPC. Quarter-over-quarter, GBPC’s revenue was higher than Q4 2019 due to the continued recovery from the impacts of Hurricane Dorian in September 2019.

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

Q4 Electric Revenues
millions of USD

	2020	2019
Residential	**$ 32**	$ 35
Commercial	**40**	49
Industrial	**5**	6
Other	**2**	3
Total	**$ 79**	$ 93

Annual Electric Revenues
millions of USD

	2020	2019
Residential	**$ 116**	$ 125
Commercial	**161**	198
Industrial	**21**	21
Other	**12**	15
Total	**$ 310**	$ 359

Q4 Electric Sales Volumes

GWh	**2020**	2019
Residential	**124**	115
Commercial	**169**	188
Industrial	**19**	19
Other	**1**	4
Total	**313**	326

Annual Electric Sales Volumes

GWh	**2020**	2019
Residential	**493**	463
Commercial	**650**	742
Industrial	**80**	78
Other	**17**	15
Total	**1,240**	1,298

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power decreased $23 million to $35 million in Q4 2020, compared to $58 million in Q4 2019. For the year ended December 31, 2020, regulated fuel for generation and purchased power decreased $71 million to $145 million compared to $216 million in 2019. The decreases in both periods were as a result of lower oil prices at BLPC.

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

Q4 Production Volumes
GWh

	2020	2019
Oil	**314**	332
Hydro	**7**	6
Solar	**4**	4
Purchased power	**12**	9
Total	**337**	351

Annual Production Volumes
GWh

	2020	2019
Oil	**1,247**	1,338
Hydro	**19**	20
Solar	**17**	19
Purchased power	**52**	34
Total	**1,335**	1,411

Q4 Average Fuel Costs

US dollars	**2020**	2019
Dollars per MWh	**$ 105**	$ 135

Annual Average Fuel Costs

US dollars	**2020**	2019
Dollars per MWh	**$ 102**	$ 125

Average fuel cost per MWh decreased in Q4 2020 and for the year ended December 31, 2020, compared to the same periods in 2019, due to lower oil prices.

Regulatory Recovery Mechanisms

BLPC

BLPC is regulated by the FTC, an independent regulator. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested. BLPC's fuel costs flow through a fuel pass-through mechanism which provides opportunity to recover all prudently incurred fuel costs from customers in a timely manner. The FTC approves the calculation of the fuel charge, which is adjusted on a monthly basis.

GBPC

GBPC is regulated by the GBPA. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. GBPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner.

GBPC maintains insurance for its generation facilities. As with most utilities, its transmission and distribution networks are self-insured. In 2019 Hurricane Dorian restoration costs for GBPC self-insured assets were $15 million USD. In January 2020, the GBPA approved the deferral of these costs through a regulated asset with recovery through rates over a five-year period. Recovery of the asset began January 1, 2021.

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

As a component of its regulatory agreement, GBPC has an Earnings Share Mechanism to allow for earnings on rate base to be deferred to a regulatory asset or liability at the rate of 50 per cent of amounts below a 7.34 per cent return on rate base and 50 per cent of amounts above 9.34 per cent return on rate base, respectively.

Domlec

Domlec is regulated by the IRC. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. Substantially all of Domlec fuel costs flow through a fuel pass-through mechanism which provides opportunity to recover prudently incurred fuel costs from customers in a timely manner.

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 December 31				Year ended December 31		
		2020		2019		**2020**		2019
Operating revenues – regulated gas (1)	**$**	**234**	$	228	**$**	**780**	$	832
Operating revenues – non-regulated		**3**		3		**12**		12
Total operating revenue	**$**	**237**	$	231	**$**	**792**	$	844
Regulated cost of natural gas	**$**	**80**	$	76	**$**	**221**	$	264
Income from equity investments	**$**	**4**	$	3	**$**	**14**	$	17
Contribution to consolidated net income	**$**	**35**	$	37	**$**	**122**	$	139
Contribution to consolidated net income – CAD	**$**	**45**	$	51	**$**	**162**	$	183
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.18**	$	0.21	**$**	**0.65**	$	0.76
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.30**	$	1.32	**$**	**1.33**	$	1.33
EBITDA	**$**	**81**	$	84	**$**	**294**	$	311
EBITDA – CAD	**$**	**104**	$	114	**$**	**392**	$	413

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2019 - $11 million) for the three months ended December 31, 2020 and $45 million (2019 - $45 million) for the year ended December 31, 2020, however, it is excluded from the gas revenues analysis below.

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

For the millions of US dollars		Three months ended December 31				Year ended December 31		
		2020		2019		**2020**		2019
PGS	**$**	**13**	$	12	**$**	**52**	$	54
NMGC		**12**		15		**30**		46
Other		**10**		10		**40**		39
Contribution to adjusted consolidated net income	**$**	**35**	$	37	**$**	**122**	$	139

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2019	**$ 37**	**$ 139**
Increased (decreased) gas operating revenues - see Operating Revenues - Regulated Gas below	6	(43)
Increased (decreased) cost of natural gas sold - see Regulated Cost of Natural Gas below	(4)	43
Recognition of tax benefits related to change in treatment of NOL carryforwards at NMGC in Q3 2019	-	(5)
Decreased gas operating revenues as a result of recognition of tax reform benefits at NMGC in Q2 2019	-	(9)
Other	(4)	(3)
Contribution to consolidated net income – 2020	**$ 35**	**$ 122**

Gas Utilities and Infrastructure's CAD contribution to consolidated net income decreased $6 million in Q4 2020, compared to Q4 2019. For the year ended December 31, 2020, Gas Utilities and Infrastructure's CAD contribution to consolidated net income decreased $21 million compared to 2019. The decrease in both periods was the result of lower revenues due to warmer weather at NMGC, impacts of COVID-19 on commercial sales at PGS, and higher OM&G costs at PGS and NMGC. These impacts were partially offset by customer growth at PGS, increased AFUDC earnings at PGS, and higher return on investment in the cast iron and bare steel replacement rider at PGS. For the year ended December 31, 2020, the decrease was also due to the Q3 2019 recognition of tax benefits related to a change in treatment of NOL carryforwards and tax reform benefits recognized in Q2 2019 at NMGC.

The foreign exchange rate had minimal impact on CAD earnings in Q4 2020 and for the year ended December 31, 2020.

Operating Revenues – Regulated Gas

Gas Utilities and Infrastructure's operating revenues increased $6 million to $234 million in Q4 2020, compared to $228 million in Q4 2019 due to higher clause related revenues and customer growth at PGS partially offset by lower off-system sales at PGS and lower commercial sales related to the COVID-19 pandemic at PGS.

For the year ended December 31, 2020, operating revenues decreased $52 million to $780 million, compared to $832 million in 2019 due to lower clause-related revenues, lower off-system sales at PGS, warmer weather at NMGC and lower commercial sales related to the COVID-19 pandemic at PGS. This decrease was partially offset by customer growth at PGS. For the year ended December 31, 2020, the decrease was also due to NMGC's recognition of tax reform benefits in Q2 2019.

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

Q4 Gas Revenues
millions of US dollars

		2020		2019
Residential	**$**	**122**	$	109
Commercial		**63**		63
Industrial (1)		**11**		9
Other (2)		**27**		36
Total (3)	**$**	**223**	$	217

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $11 million of finance income from Brunswick Pipeline (2019 – $11 million).

Annual Gas Revenues
millions of US dollars

		2020		2019
Residential	**$**	**372**	$	379
Commercial		**207**		225
Industrial (1)		**41**		37
Other (2)		**115**		146
Total (3)	**$**	**735**	$	787

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $45 million of finance income from Brunswick Pipeline (2019 – $45 million).

Q4 Gas Volumes
Therms (millions)

	2020	2019
Residential	**132**	138
Commercial	**220**	225
Industrial	**388**	376
Other	**59**	88
Total	**799**	827

Annual Gas Volumes
Therms (millions)

	2020	2019
Residential	**405**	413
Commercial	**767**	830
Industrial	**1,586**	1,482
Other	**298**	317
Total	**3,056**	3,042

Regulated Cost of Natural Gas

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

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

Regulated cost of natural gas increased $4 million to $80 million in Q4 2020, compared to $76 million in Q4 2019 due to higher commodity costs at PGS and NMGC.

For the year ended December 31, 2020, regulated cost of natural gas decreased $43 million to $221 million in Q4 2020, compared to $264 million in 2019. The decrease was due to lower commodity costs at PGS and NMGC in the first three quarters of the year, lower system supply to customers and lower volume of off-system sales at PGS.

Gas sales by type are summarized in the following table:

Q4 Gas Volumes by Type
Therms (millions)

	2020	2019
System supply	**197**	235
Transportation	**602**	592
Total	**799**	827

Annual Gas Volumes by Type
Therms (millions)

	2020	2019
System supply	**690**	754
Transportation	**2,366**	2,288
Total	**3,056**	3,042

Regulatory Recovery Mechanisms

PGS

PGS is regulated by the FPSC. The FPSC sets rates at a level that allows utilities such as PGS to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

Other Cost Recovery

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

Other Cost Recovery Clauses
The FPSC annually approves cost-recovery rates for conservation costs including a return on capital invested incurred in developing and implementing energy conservation programs. PGS has a Cast Iron/Bare Steel Pipe Replacement clause to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. In February 2017, the FPSC approved expansion of the Cast Iron/Bare Steel clause to allow recovery of accelerated replacement of certain obsolete plastic pipe. PGS estimates that all cast iron and bare steel pipe will be removed from its system by 2022, with replacement of obsolete plastic pipe continuing until 2028 under the rider.

NMGC

NMGC is subject to regulation by the NMPRC. The NMPRC sets rates at a level that allows NMGC to collect total revenues equal to its cost of providing service, plus an appropriate return on invested capital.

Other Cost Recovery

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

On a monthly basis, NMGC can adjust charges based on next month's expected cost of gas and any prior month under-recovery or over-recovery. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that continued use of the PGAC is reasonable and necessary. In December 2020, NMGC received approval of its PGAC Continuation Filing for the four-year period ending December 2024.

Weather Normalization Mechanism
In July 2019, the NMPRC approved changes to the company's rate design to include a Weather Normalization Mechanism. This clause is designed to lower the variability of weather impacts during the October through April heating seasons. The Weather Normalization Mechanism will allow customer rates and company revenue to be more predictable by partially removing the impact of warmer than usual or colder than usual weather. Weather-related revenue increases or decreases experienced from October to April will be adjusted annually in October of the following heating season.

IMP Regulatory Asset
A portion of NMGC's annual spend on infrastructure is for integrity management programs ("IMP"), or the replacement and update of legacy systems. These programs are driven both by NMGC integrity management plans and federal and state mandates. In December 2020, NMGC received approval through its rate case to defer costs through an IMP regulatory asset for certain of its IMP capital investments occurring between January 1, 2022 and December 31, 2023 and will seek recovery for the regulatory asset in its next rate case filing.

Other

For the millions of Canadian dollars (except per share amounts)		Three months ended December 31 **2020**		2019		Year ended December 31 **2020**		2019
Marketing and trading margin (1) (2)	**$**	**22**	$	28	**$**	**38**	$	31
Electricity and capacity sales (3)		**4**		2		**16**		118
Other non-regulated operating revenue		**8**		1		**21**		31
Total operating revenues – non-regulated	**$**	**34**	$	31	**$**	**75**	$	180
Intercompany revenue (4)	**$**	**3**	$	3	**$**	**13**	$	20
Non-regulated fuel for generation and purchased power (5)	**$**	**3**	$	2	**$**	**15**	$	68
Income from equity investments	**$**	**7**	$	7	**$**	**24**	$	32
Interest expense, net	**$**	**71**	$	81	**$**	**301**	$	337
Adjusted contribution to consolidated net income (loss)	**$**	**(23)**	$	(58)	**$**	**(252)**	$	(286)
Gain on sale, net of tax and transaction costs	**$**	**-**	$	-	**$**	**309**	$	-
Impairment charges, net of tax		**-**		-		**(26)**		-
After-tax derivative MTM gain (loss)		**83**		81		**(12)**		73
Contribution to consolidated net income (loss)	**$**	**60**	$	23	**$**	**19**	$	(213)
Adjusted contribution to consolidated earnings per common share – basic	**$**	**(0.09)**	$	(0.24)	**$**	**(1.02)**	$	(1.19)
Contribution to consolidated earnings per common share – basic	**$**	**0.24**	$	0.09	**$**	**0.08**	$	(0.89)
Adjusted EBITDA	**$**	**50**	$	2	**$**	**25**	$	9

(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 MTM gain of $109 million in Q4 2020 (2019 - $119 million gain) and a loss of $46 million for the year ended December 31,2020 (2019 – $100 million gain).
(3) Electricity and capacity sales exclude a pre-tax MTM of nil in Q4 2020 (2019 - nil) and nil for the year ended December 31, 2020 (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 MTM of nil in Q4 2020 (2019 - $1 million loss) and a $3 million gain for the year ended December 31, 2020 (2019 – $2 million loss).

Other's adjusted contribution to consolidated net income is summarized in the following table:

For the millions of Canadian dollars		Three months ended December 31 **2020**		2019		Year ended December 31 **2020**		2019
Emera Energy	**$**	**15**	$	18	**$**	**17**	$	37
Corporate		**(37)**		(75)		**(267)**		(322)
Other		**(1)**		(1)		**(2)**		(1)
Adjusted contribution to consolidated net income (loss)	**$**	**(23)**	$	(58)	**$**	**(252)**	$	(286)

Mark-to-Market Adjustments

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

Emera Energy has a number of asset management agreements ("AMA") with counterparties, including local gas distribution utilities, power utilities and natural gas producers in North America. The AMAs involve Emera Energy buying or selling gas for a specific term, and the corresponding release of the counterparties' gas transportation/storage capacity to Emera Energy. MTM adjustments on these AMAs arise on the price differential between the point where gas is sourced and where it is delivered. At inception, the MTM adjustment is offset fully by the value of the corresponding gas transportation asset, which is amortized over the term of the AMA contract.

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

In 2020 Emera Corporate entered into foreign exchange forwards to manage the cash flow risk of forecasted USD cash inflows. Fluctuations in the foreign exchange rate result in MTM gains or losses recorded in income.

Net Income

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

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income (loss) – 2019	**$ 23**	**$ (213)**
Increased (decreased) marketing and trading margin - see Emera Energy below	(6)	7
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 corporate long-term debt	10	30
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 $2 million recovery related to MTM	-	(11)
Timing of preferred stock dividends issued	(11)	-
TGH award, net of tax and legal costs	36	36
Impact of sale of NEGG and Bayside Power, net of tax	1	(21)
Impairment charges recognized on certain other assets	-	(26)
Gain on sale of Emera Maine, net of tax and transaction costs	-	309
Changes in MTM gains and losses in both periods are due to changes in existing hedging positions and changes in amortization on gas transportation assets at Emera Energy, partially offset by foreign exchange gains on cash flow hedges	2	(87)
Decreased income from Bear Swamp equity investment due to reduced energy deliveries resulting from a third-party transmission line outage, lower New England capacity prices and less favourable energy conditions	-	(8)
2019 Corporate share of the unrecoverable loss at GBPC facilities	6	15
Other	(1)	(2)
Contribution to consolidated net income (loss) – 2020	**$ 60**	**$ 19**

Excluding the change in MTM, gain on sale of Emera Maine and impairment charges recognized on certain other assets, Other's contribution to consolidated net income increased by $35 million in Q4 2020, compared to Q4 2019. For the year ended December 31, 2020, Other's contribution to consolidated net income increased $34 million, compared to the same period in 2019. The increase in both periods was primarily due to the TGH award, lower corporate interest and the 2019 recognition of the Corporate share of the unrecoverable loss on GBPC facilities. The quarter-over-quarter increase was partially offset by timing of preferred stock dividends and decreased marketing and trading margin. Year-over-year increase was also due to higher marketing and trading margin partially offset by the impact of the sale of NEGG and Bayside, 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

EES derives revenue and earnings from the wholesale marketing and trading of natural gas, electricity and other energy-related commodities and derivatives within the Company's risk tolerances, including those related to value-at-risk ("VaR") and credit exposure. EES purchases and sells physical natural gas and electricity, the related transportation and transmission capacity rights, and provides energy asset management services. The primary market area for the natural gas and power marketing and trading business is northeastern North America, including the Marcellus and Utica shale supply areas. EES also participates in the Florida, US Gulf Coast and Midwest/Central Canadian natural gas markets. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. EES operates in a competitive environment, and the business relies on knowledge of the region's energy markets, understanding of pipeline and transmission infrastructure, a network of counterparty relationships and a focus on customer service. EES manages its commodity risk by limiting open positions, utilizing financial products to hedge purchases and sales, and investing in transportation capacity rights to enable movement across its portfolio.

Marketing and Trading

Marketing and trading margin decreased $6 million in Q4 2020, compared to Q4 2019 primarily due to lower hedged margin net of fixed commitments for gas transportation and storage.

For the year ended December 31, 2020, marketing and trading margin increased $7 million compared to the same period in 2019. This increase was primarily due to increased hedged margin net of fixed commitments for gas transportation storage assets in the summer months, partially offset by less favourable winter market conditions, specifically warmer than normal Q1 winter weather and lower natural gas prices in 2020 compared to 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 year ended December 31, 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. Refer to the "Business Overview and Outlook – COVID-19 Pandemic" section of this document 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. There have been no significant customer defaults as a result of bankruptcies with many customer accounts secured by deposits. As of December 31, 2020, adjustments to the allowance for credit losses have increased but 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 working 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, timing and effectiveness of vaccinations, 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 and debt raised at the utilities 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 of this document.

Emera has credit facilities with varying maturities that cumulatively provide $3.7 billion of credit, with approximately $1.7 billion undrawn and available at December 31, 2020. The Company was holding a cash balance of $254 million at December 31, 2020. Refer to the "Debt Management" section below for further details. Refer to notes 23 and 25 in the consolidated financial statements for additional information regarding the credit facilities.

Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the years ended December 31, 2020 and 2019 include:

millions of Canadian dollars		2020	2019	$ Change
Cash, cash equivalents and restricted cash, beginning of period	$	**274** $	372 $	(98)
Provided by (used in):				
Operating cash flow before changes in working capital		**1,420**	1,598	(178)
Change in working capital		**217**	(73)	290
Operating activities	$	**1,637** $	1,525	112
Investing activities		**(1,224)**	(1,617)	393
Financing activities		**(372)**	14	(386)
Effect of exchange rate changes on cash and cash equivalents		**(61)**	(20)	(41)
Cash, cash equivalents, restricted cash and cash included in assets held for sale, end of period	$	**254** $	274 $	(20)

Cash Flow from Operating Activities

Net cash provided by operating activities increased $112 million to $1,637 million for the year ended December 31, 2020, compared to $1,525 million in 2019.

Cash from operations before changes in working capital decreased $178 million in 2020. The decrease was primarily due to the impact of the sale of Emera Maine in Q1 2020, lower earnings at NSPI, and higher under-recovery of clause related costs at Tampa Electric.

Changes in working capital increased operating cash flows by $290 million. The increase was due to favourable changes in cash collateral positions on derivative instruments at NSPI, decreased investment in fuel inventory at NSPI, and the receipt in 2020 of a 2019 income tax refund at NSPI. This was partially offset by timing of accounts payable payments at Tampa Electric and NMGC.

Cash Flow used in Investing Activities

Net cash used in investing activities decreased $393 million to $1,224 million for the year ended December 31, 2020, compared to $1,617 million in 2019. In 2020, Emera received proceeds of $1.4 billion on the sale of Emera Maine, compared to proceeds of $875 million on dispositions in 2019, primarily from the sale of the NEGG and Bayside facilities. This increase in proceeds was partially offset by an increase in capital expenditures in 2020.

Capital expenditures for the year ended December 31, 2020, including AFUDC, were $2,668 million compared to $2,516 million in 2019. Details of the 2020 capital spend by segment are shown below:

- $1,415 million - Florida Electric Utility (2019 – $1,414 million);
- $342 million - Canadian Electric Utilities (2019 – $389 million);
- $149 million - Other Electric Utilities (2019 – $200 million);
- $758 million - Gas Utilities and Infrastructure (2019 – $450 million); and
- $4 million - Other (2019 – $63 million).

Cash Flow from Financing Activities

Net cash used in financing activities increased $386 million to $372 million for the year ended December 31, 2020, compared to cash provided by financing activities of $14 million in 2019. The increase was due to 2019 proceeds from Emera's non-revolving credit facilities, net repayment of debt at TECO Finance, higher net repayments of Emera'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, proceeds from short-term debt at Tampa Electric and PGS, lower net repayments of NSPI's committed credit facilities and the 2019 retirement of long-term debt at NSPI.

Working Capital

As at December 31, 2020, Emera's cash and cash equivalents were $220 million (2019 – $222 million) and Emera's investment in non-cash working capital was $266 million (2019 – $566 million). Of the cash and cash equivalents held at December 31, 2020, $197 million was held by Emera's foreign subsidiaries (2019 – $208 million). A portion of these funds are invested in countries that have certain exchange controls, approvals, and processes for repatriation. Such funds are available to fund local operating and capital requirements unless repatriated.

Contractual Obligations

As at December 31, 2020, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2021	2022	2023	2024	2025	Thereafter	Total
Long-term debt principal	$ 1,382	$ 407	$ 809	$ 820	$ 226	$ 10,182	$ 13,826
Interest payment obligations (1)	585	552	531	516	497	6,364	9,045
Purchased power (2)	231	218	216	218	224	2,242	3,349
Transportation (3)	518	393	339	306	282	2,704	4,542
Pension and post-retirement obligations (4)	30	37	31	32	31	184	345
Capital projects	394	98	76	-	-	-	568
Fuel, gas supply and storage	494	91	6	1	-	-	592
Asset retirement obligations	21	2	2	7	2	391	425
Long-term service agreements (5)	43	41	36	33	34	92	279
Equity investment commitments (6)	-	240	-	-	-	-	240
Leases and other (7)	16	17	16	15	8	118	190
Demand side management	40	45	-	-	-	-	85
Long-term payable	5	5	5	-	-	-	15
	$ 3,759	$ 2,146	$ 2,067	$ 1,948	$ 1,304	$ 22,277	$ 33,501

(1) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2020, including any expected required payment under associated swap agreements.
(2) Annual requirement to purchase electricity production from IPP's or other utilities over varying contract lengths.
(3) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $149 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(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) Maintenance of certain generating equipment, services related to a generation facility and wind operating agreements, outsourced management of computer and communication infrastructure and vegetation management.
(6) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
(7) 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 achieved first power on the first of four generators at Muskrat Falls on September 22, 2020 and continues to work toward completing 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, which is anticipated to take place in 2021. On December 16, 2020, the UARB approved NSPML's 2021 interim assessment for recovery from NSPI of Maritime Link costs of approximately $172 million subject to a holdback of $10 million with similar terms as previously approved by the UARB and a potential long-term deferral of up to $23 million in depreciation expense dependent upon the timing of commencement of the NS Block.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. 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. On December 16, 2020, the UARB approved the 2021 interim cost assessment of approximately $172 million. 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 38-year commitment period are dependent on regulatory filings with the UARB

Once Muskrat Falls and LIL have achieved full power, the commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties relating to the Maritime Link and LIL.

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, the obligations are included within "Leases and other" in the above table.

Forecasted Gross Consolidated Capital Expenditures

2021 forecasted gross consolidated capital expenditures are as follows:

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Total
Generation	$ 617	$ 150	$ 55	$ -	$ -	$ 822
New renewable generation	176	-	96	-	-	272
Transmission	73	60	2	-	-	135
Distribution	448	100	44	-	-	592
Gas transmission and distribution	-	-	-	509	-	509
Facilities, equipment, vehicles, and other	152	60	16	36	2	266
	$ 1,466	$ 370	$ 213	$ 545	$ 2	$ 2,596

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.7 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 – Unsecured committed revolving credit facility	June 2024	$ 900	$ 286	$ 614
TEC – in USD – Unsecured committed revolving credit facility (1)	March 2023	800	346	454
NSPI – Unsecured committed revolving credit facility	October 2024	600	300	300
Emera – Unsecured non-revolving facility	December 2021	400	400	-
TECO Finance – in USD – Unsecured committed revolving credit facility	March 2023	400	161	239
TEC – in USD – Unsecured non-revolving facility (1)	February 2021	300	300	-
TEC – in USD – Accounts receivable collateralized borrowing facility (1)	March 2021	150	130	20
NMGC – in USD – Unsecured committed revolving credit facility	March 2023	125	19	106
Other – in USD – Unsecured committed revolving credit facilities	Various	35	20	15

(1) These facilities are available for use by Tampa Electric and PGS. At December 31, 2020, Tampa Electric had utilized $562 million USD and PGS had utilized $214 million USD of the facilities.

Emera and its subsidiaries have certain financial and other covenants associated with their debt and credit facilities. Covenants are tested regularly, and the Company is in compliance with covenant requirements as at December 31, 2020. Emera's significant covenant is listed below:

	Financial Covenant	Requirement	As at December 31, 2020
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.56 : 1

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 on either the London interbank deposit rate ("LIBOR"), prime rate or the federal funds rate, plus a margin. On January 29, 2021, TEC extended the maturity date of the agreement to April 29, 2021 with no other changes in terms.

On December 18, 2020, TEC amended and restated its bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023 and increased the amount of the commitment by the lenders to $800 million USD from $400 million USD. The credit facility bears interest based on either the LIBOR, the Wells Fargo Bank's prime rate, or the federal funds rate, plus a margin. The amended facility now includes a $80 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

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 December 31, 2020, BLPC had drawn $77 million BBD ($38 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.

Gas Utilities and Infrastructure

On February 5, 2021, NMGC completed an issuance of $220 million USD senior notes. The issuance included $70 million USD senior notes that bear interest at a rate of 2.26 per cent with a maturity date of February 5, 2031, $65 million USD senior notes that bear interest at a rate of 2.51 per cent and with a maturity date of February 5, 2036, and $85 million USD senior notes that bear interest at a rate of 3.34 per cent with a maturity date of February 5, 2051. Proceeds from this issuance were used to repay a $200 million USD note, due in 2021 and for general corporate purposes. These notes were classified as long-term debt at December 31, 2020.

On December 18, 2020, NMGC amended and restated its $125 million USD bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023. The credit facility bears interest based on either the LIBOR, JP Morgan Chase Bank's prime rate, or the federal funds rate, plus a margin. The amended facility now includes a $30 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

Other

On February 28, 2020, TECO 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 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.

On December 1, 2020, Emera extended the maturity date of its $400 million non-revolving term loan from December 15, 2020 to December 16, 2021. There were no other significant changes in commercial terms from the prior agreement.

On December 18, 2020, TECO Finance amended and restated its $400 million USD bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023. The credit facility bears interest based on either the LIBOR, JP Morgan Chase Bank's prime rate, or the federal funds rate, plus a margin. The facility now includes a $50 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

Credit Ratings

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

	Fitch	S&P	Moody's	DBRS
Emera Inc.	BBB (Stable)	BBB- (Stable)	Baa3 (Stable)	N/A
TECO Energy/TECO Finance	N/A	BBB- (Stable)	Baa1 (Positive)	N/A
TEC	A (Stable)	BBB+ (Stable)	A3 (Positive)	N/A
NMGC	BBB+ (Stable)	N/A	N/A	N/A
NSPI	N/A	BBB+ (Stable)	N/A	A (low) (Stable)

On December 21, 2020, Moody's Investor Services upgraded its senior unsecured bank credit rating on TECO Energy to Baa1 from Baa2. Moody's also affirmed TEC's A3 senior unsecured rating. The rating outlook remains positive.

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.

Share Capital

Emera

As at December 31, 2020, Emera had 251.43 million (2019 – 242.48 million) common shares issued and outstanding. For the year ended December 31, 2020, 8.95 million common shares were issued (2019 – 8.36 million) for net proceeds of $489 million (2019 – $400 million).

As at December 31, 2020, Emera had 41 million preferred shares issued and outstanding (2019 – 41 million).

PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three-year period. The cash required in 2021 for defined benefit pension plans is expected to be $41 million (2020 – $41 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

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

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

Emera's projected contributions to defined contribution pension plans, are $44 million for 2021 (2020 – $45 million).

Defined Benefit Pension Plan Summary

in millions of Canadian dollars

Plans by region	TECO Energy	NSPI	Maine (1)	Caribbean	Total
Assets as at December 31, 2020	$ 1,150	$ 1,445	$ -	$ 10	$ 2,605
Accounting obligation at December 31, 2020	1,168	1,576	-	15	2,759
Accounting expense during fiscal 2020	$ 19	$ 7	$ 1	$ 1	$ 28

(1) On March 24, 2020, Emera completed the sale of Emera Maine.

OFF-BALANCE SHEET ARRANGEMENTS

Defeasance

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2020 totalled $582 million (2019 – $740 million). The securities are held in trust for an affiliate of the Province of Nova Scotia. Approximately 78 per cent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

Guarantees and Letters of Credit

Emera has guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2020:

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

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.

NSPI has issued guarantees in the amount of $18 million USD on behalf of its subsidiary, NS Power Energy Marketing Incorporated ("NSPEMI"), to secure obligations under purchase agreements with third-party suppliers. The guarantees have terms of varying lengths and will be renewed as required.

The Company has standby letters of credit and surety bonds in the amount of $55 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 December 31, 2020 was $63 million (December 31, 2019 - $52 million).

DIVIDEND PAYOUT RATIO

Emera has provided annual dividend growth guidance of four to five per cent through 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. Emera Incorporated's common share dividends paid in 2020 were $2.4750 ($0.6125 in Q1, Q2, and Q3 and $0.6375 in Q4) per common share and $2.3750 ($0.5875 in Q1, Q2, and Q3 and $0.6125 in Q4) per common share for 2019, representing a payout ratio of 91 per cent of adjusted net income in 2020 and 91 per cent in 2019.

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 quarterly dividend payment at the increased rate was paid on November 16, 2020.

TRANSACTIONS WITH RELATED PARTIES

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

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

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $139 million for the year ended December 31, 2020 (2019 - $107 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.

For further details, refer to the "Business Overview and Outlook - Canadian Electric Utilities - ENL" and "Contractual Obligations" sections.

- Natural gas transportation capacity purchases from M&NP are reported in the Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $18 million for the year ended December 31, 2020 (2019 - $63 million).

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

ENTERPRISE RISK AND RISK MANAGEMENT

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

The Company's financial risk management activities are focused on those areas that most significantly impact profitability, quality and consistency of income, and cash flow. Emera's risk management focus extends to key operational risks including safety and environment, which represent core values of Emera. In this section, Emera describes the principal risks that management believes could materially affect its business, revenues, operating income, net income, net assets, liquidity or capital resources. The nature of risk is such that no list is comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

Regulatory and Political Risk

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments. Regulatory and political risk can include change in regulatory frameworks, shifts in government policy, and regulatory decisions.

As cost-of-service utilities with an obligation to serve customers, Emera's utilities operate under formal regulatory frameworks, and must obtain regulatory approval to change or add rates and/or riders. Costs and investments can be recovered upon approval by the respective regulator as an adjustment to rates and/or riders, which normally requires a public hearing process or may be mandated by other governmental bodies. Emera also holds investments in entities in which it has significant influence, and which are subject to regulatory and political risk including NSPML, LIL, M&NP and Lucelec. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the CER on a complaint basis, as opposed to the regulatory approval process described above. In the absence of a complaint, the CER does not normally undertake a detailed examination of Brunswick Pipeline's tolls, which are subject to a firm service agreement expiring in 2034, with Repsol Energy Canada ("REC"). The agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract.

Changes in government and shifts in government policy can impact the commercial and regulatory frameworks under which Emera and its subsidiaries operate. This includes initiatives regarding deregulation or restructuring of the energy industry. Deregulation or restructuring of the energy industry may result in increased competition and unrecovered costs that could adversely affect operations, net income and cash flows. Recently state and local policies in some US jurisdictions have sought to prevent or limit the ability of utilities to provide customers the choice to use natural gas. Changes in applicable state or local laws and regulations could adversely impact PGS and NMGC.

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

Global Climate Change Risk

The Company is subject to risks that may arise from the impacts of climate change. There is increasing public concern about climate change and growing support for reducing carbon emissions. Municipal, state, provincial and federal governments have been setting policies and enacting laws and regulations to deal with climate change impacts in a variety of ways, including decarbonization initiatives and promotion of cleaner energy and renewable energy generation of electricity. Refer to “Changes in Environmental Legislation” risk below. Insurance companies have begun to limit their exposure to coal-fired electricity generation and are evaluating the medium and long-term impacts of climate change which may result in fewer insurers, more restrictive coverage and increased premiums. Refer to the “Markets” section below and “Uninsured Risk”.

Climate change may lead to increased frequency and intensity of weather events and related impacts such as storms, ice storms, hurricanes, cyclones, heavy rainfall, extreme winds, wildfires, flooding and storm surge. The potential impacts of climate change, such as rising sea levels and larger storm surges from more intense hurricanes, can combine to produce even greater damage to coastal generation and other facilities. Climate change is also characterized by rising global temperatures. Increased air temperatures may bring increased frequency and severity of wildfires within the Company’s service territories. Refer to “Weather Risk” and “System Operating and Maintenance Risks”.

The Company has made significant investments to facilitate the use of renewable and lower-carbon energy including wind generation, the Maritime Link in Atlantic Canada, and in Florida, solar generation and the modernization of the Big Bend Power Station. Tampa Electric has taken significant steps to reduce overall emissions at its facilities. Tampa Electric expects to achieve a 45 per cent reduction in GHG emissions compared to 2005 levels by 2023 as a result of its investment in solar and natural gas generation which will reduce coal generation. Since 2005, NSPI has reduced carbon emissions by 35 per cent, exceeding the 2030 reduction target of 30 per cent set at the COP 21 Climate Conference, and expects to achieve a greater-than 50 per cent reduction by 2030; nearly double the Government of Canada’s target set under the Paris Agreement. NSPI expects to achieve compliance with a provincially mandated target of at least 40 per cent of energy generated from renewable sources over the 2020-to-2022 period. Both the Government of Nova Scotia and the Government of Canada have enacted or introduced legislation that includes goals of net-zero GHG emissions by 2050. NSPI continues to work with both the provincial and federal governments on measures to address their carbon reduction goals. Within Emera’s natural gas utilities, there are ongoing efforts to reduce methane and carbon emissions through replacement of aging infrastructure, more efficient operations, operational and supply chain optimization, and support of public policy initiatives that address the effects of climate change.

The Company’s long-term capital investment plan includes significant investment across the portfolio in renewable and cleaner generation, infrastructure modernization, storm hardening, energy storage and customer-focused technologies. All these initiatives contribute toward mitigating the potential impacts of climate change. The Company continues to engage with government, regulators, industry partners and stakeholders to share information and participate in the development of climate change related policies and initiatives.

Physical Impacts

The Company is subject to physical risks that arise, or may arise, from global climate change, including damage to operating assets from more frequent and intense weather events and from wildfires due to warming air temperatures and increasing drought conditions. Substantially all of the Company’s fossil fueled generation assets are located at or near coastal sites and as such are exposed to the separate and combined effects of rising sea levels and increasing storm intensity, including storm surges and flooding. Refer to “Weather Risk” for further information.

These risks are mitigated to an extent through features such as flood walls at certain plants and through the location of plants on higher ground. Planned investments in under-grounding parts of the electricity infrastructure contributes to risk mitigation, as does insurance coverage (for assets other than electricity transmission and distribution assets). In addition, implementation of regulatory mechanisms for recovery of costs, such as storm reserves and regulatory deferral accounts help to smooth out the recovery of storm restoration costs over time.

Reputation

Failure to address issues related to climate change could affect Emera's reputation with stakeholders, its ability to operate and grow, and the Company's access to, and cost of, capital. Refer to "Liquidity and Capital Market Risk". The Company seeks to mitigate this in part by moving away from higher-carbon generation in favour of lower-carbon generation and non-emitting renewable generation.

Markets

Changing carbon-related costs, policy and regulatory changes and shifts in supply and demand factors could lead to more expensive or more scarce products and services that are required by the Company in its operations. This could lead to supply shortages, delivery delays and the need to source alternate products and services. The Company seeks to mitigate these risks through close monitoring of such developments and adaptive changes to supply chain procurement strategies.

Given concerns regarding carbon-emitting generation, those assets and businesses may, over time, become difficult (or uneconomic) to insure in commercial insurance markets. In the short term this may be mitigated through increased investment in engineered protection or alternative risk financing (such as funded self-insurance or regulatory structures, including storm reserves). Longer-term mitigation may be achieved through infrastructure siting decisions and further engineered protections. This risk is also mitigated through the continued transition away from high-carbon generation sources to sources with low or zero carbon emissions.

Policy

Government and regulatory initiatives, including greenhouse gas emissions standards, air emissions standards and generation mix standards, are being proposed and adopted in many jurisdictions in response to concerns regarding the effects of climate change. In some jurisdictions, government policy has included timelines for mandated shutdowns of coal generating facilities, carbon pricing, emissions limits and cap and trade mechanisms. Over the medium and longer terms, this could potentially lead to a significant portion of hydrocarbon infrastructure assets being subject to additional regulation and limitations in respect of GHG emissions and operations.

The Company is committed to compliance with all climate-related and environmental legislative and regulatory requirements. Such legislative and regulatory initiatives could adversely affect Emera's operations and financial performance. Refer to "Regulatory and Political Risk" and "Changes in Environmental Legislation" risk. The Company seeks to mitigate these risks through active engagement with governments and regulators to pursue transition strategies that meet the needs of customers, stakeholders and the Company. This has included NSPI's participation in negotiated equivalency agreements in Nova Scotia to provide for an affordable transition to lower-carbon generation. Equivalency agreements allow NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent.

Regulatory

Depending on the regulatory response to government legislation and regulations, the Company may be exposed to the risk of reduced recovery through rates in respect of the affected assets. Valuation impairments could result from such regulatory outcomes. Mitigation efforts in respect of these risks include active engagement with policy makers and regulators to find mechanisms to avoid such impacts while being responsive to customers' and stakeholders' objectives.

Legal

The Company could face litigation or regulatory action related to environmental harms from carbon emissions or climate change public disclosure issues. The Company addresses these risks through compliance with all relevant laws, emissions reduction strategies and public disclosure of climate change risks.

Water Resources

For thermal plants requiring cooling water, reduced availability of water resulting from climate change could adversely impact operations or the costs of operations. The Company seeks ways to reduce and recycle water as it does in its Polk power plant in Florida, where recovered and treated wastewater is used in operations to reduce reliance on fresh water supplies in an area where water is not as abundant as in other markets.

The Company operates hydroelectric generation in certain of its markets. Such generation depends on availability of water and the hydrological profile of water sources. Changes in precipitation patterns, water temperatures and air temperatures could adversely affect the availability of water and consequently the amount of electricity that may be produced from such facilities. The Company is reinvesting in the efficiency of certain hydroelectric generation facilities to increase generation capacity and continues to monitor changing hydrology patterns. Such issues may also affect the availability of third-party owned hydroelectricity purchased power sources.

Weather Risk

The Company is subject to risks that arise or may arise from weather including seasonal variations impacting energy sales, more frequent and intense weather events, changing air temperatures, wildfires and extreme weather conditions associated with climate change. Refer to "Global Climate Change Risk".

Fluctuations in the amount of electricity or natural gas used by customers can vary significantly in response to seasonal changes in weather and could impact the operations, results of operations, financial condition, and cash flows of the Company's utilities. For example, electrical utilities operating in the US Northeast or Atlantic Canada could see lower demand in winter months if temperatures are warmer than expected. Further, extreme weather conditions such as hurricanes and other severe weather conditions which may be associated with climate change could cause these seasonal fluctuations to be more pronounced. In the absence of a regulatory recovery mechanism for unanticipated costs, such events could influence the Company's results of operations, financial conditions or cash flows.

Extreme weather events create a risk of physical damage to the Company's assets. High winds can impact structures and cause widespread damage to transmission and distribution infrastructure. Increased frequency and severity of weather events increases the likelihood that the duration of power outages and fuel supply disruptions could increase. Increased intensity of flooding and storm surge could adversely affect the operations of utilities and in particular generation assets.

Each of Emera's regulated electric utilities have programs for storm hardening of transmission and distribution facilities to minimize damage, but there can be no assurance that these measures will fully mitigate the risk. This risk to transmission and distribution facilities is typically not insured, and as such the restoration cost is generally recovered through regulatory processes, either in advance through reserves or designated self-insurance funds, or after the fact through the establishment of regulatory assets. Recovery is not assured and is subject to prudency review. The risk to generation assets is, in part, mitigated through the design, siting, construction and maintenance of such facilities, regular risk assessments, engineered mitigation, emergency storm response plans and insurance.

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

Changes in Environmental Legislation

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

In 2019, NSPI completed registration under the Nova Scotia Cap-and-Trade Program Regulations. This provincial carbon pricing program meets the benchmark set by the Government of Canada. In the United States, in June 2019, the Environmental Protection Agency issued the final Affordable Clean Energy ("ACE") rule. The ACE rule establishes GHG emission guidelines for states to regulate GHG emissions from existing coal-fired electricity generating units. Individual states continue to develop or administer GHG reduction initiatives. Changes to GHG emissions standards and air emissions standards could adversely affect Emera's operations and financial performance.

Legislative or regulatory changes could influence decisions regarding early retirement of generation facilities and may result in stranded costs if the Company is not able to fully recover the costs and investment in the affected generation assets. Recovery is not assured and is subject to prudency review. Legislative or regulatory changes may curtail sales of natural gas to new customers, which could reduce future customer growth in Emera's natural gas businesses. Stricter environmental laws and enforcement of such laws in the future could increase Emera's exposure to additional liabilities and costs. These changes could also affect earnings and strategy by changing the nature and timing of capital investments.

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations authorizing the imposition of penalties for non-compliance, including fines, injunctive relief, and other sanctions. The cost of complying with current and future environmental requirements is, and may be, material to Emera. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on Emera. In addition, Emera's business could be materially affected by changes in government policy, utility regulation, and environmental and other legislation that could occur in response to environmental and climate change concerns.

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and in compliance with applicable legal requirements and Company policy. Emera has implemented this policy through the development and application of environmental management systems in its operating subsidiaries. Comprehensive audit programs are in place to regularly test compliance.

Cybersecurity Risk

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

Cyberattacks can reach the Company's networks with access to critical assets and information via their interfaces with less critical internal networks or via the public internet. Cyberattacks can also occur via personnel with direct access to critical assets or trusted networks. An outbreak of infectious disease, a pandemic or a similar public health threat, such as COVID-19, may cause disruption in normal working patterns including wide scale "work from home" policies, which could increase cybersecurity risk as the quantity of both cyberattacks and network interfaces increases. Refer to the "Public Health Risk" section below. Methods used to attack critical assets could include general purpose or energy-sector-specific malware delivered via network transfer, removable media, viruses, attachments, or links in e-mails. The methods used by attackers are continuously evolving and can be difficult to predict and detect.

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

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

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

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 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.

Energy Consumption Risk

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

Foreign Exchange Risk

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

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

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

Liquidity and Capital Market Risk

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

Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in property, plant and equipment and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions including those related to public health threats, such as the COVID-19 pandemic.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the Company's business and regulatory framework, the ability to recover costs and earn returns, diversification, leverage, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes and other severe weather events. A decrease in a credit rating could result in higher interest rates in future financings, increase borrowing costs under certain existing credit facilities, limit access to the commercial paper market or limit the availability of adequate credit support for subsidiary operations. For certain derivative instruments, if the credit ratings of the Company were reduced below investment grade, the full value of the net liability of these positions could be required to be posted as collateral. Emera manages these risks by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

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

Interest Rate Risk

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk. Emera seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt. Interest rates may be impacted by market disruptions related to public health threats, including the COVID-19 pandemic.

For Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. Regulatory ROE will generally follow the direction of interest rates, such that regulatory ROE's are likely to fall in times of reducing interest rates and rise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Project Development and Land Use Rights Risk

The Company's capital plan includes significant investment in generation, infrastructure modernization and customer-focused technologies. Any projects planned or currently in construction, particularly significant capital projects, may be subject to risks including, but not limited to, impact on costs from schedule delays, risk of cost overruns, ensuring compliance with operating and environmental requirements and other events within or beyond the Company's control. The Company's projects may also require approvals and permits at the federal, provincial, state, regional and local levels. There is no assurance that Emera will be able to obtain the necessary project approvals or applicable permits or receive regulatory approval to recover the costs in rates.

Some of the Company's assets are located on land owned by third parties, including Indigenous Peoples, and may be subject to land claims. Present or future assets may be located on lands that have been used for traditional purposes and therefore subject to specific consultations, consents, or conditions for development or operation. If the Company's rights to locate and operate its assets on any such lands are subject to expiry or become invalid, it may incur material costs to renew rights or obtain such rights. If reasonable terms for land-use rights cannot be negotiated, the Company may incur significant costs to remove and relocate its assets and restore the land. Additional costs incurred could cause projects to be uneconomical to proceed with.

Emera manages these project development and land use rights risks by deploying robust project and risk management approaches, led by teams with extensive experience in large projects. The Company consults with Indigenous Peoples in obtaining approvals, constructing, maintaining and operating such facilities, consistent with laws and public policy frameworks. Emera maintains relationships through on-going communications with stakeholders, including Indigenous Peoples, landowners and governments.

Counterparty Risk

Emera is exposed to risk related to its reliance on certain key partners, suppliers, and customers, any of which may endure financial challenges resulting from commodity price and market volatility, economic instability or adversity, adverse political or regulatory changes and other causes which may cause or contribute to such parties' insolvency, bankruptcy, restructuring or default on their contractual obligations to Emera. Emera is also exposed to potential losses related to amounts receivable from customers, energy marketing collateral deposits and derivative assets due to a counterparty's non-performance under an agreement. Counterparty creditworthiness and the ability of key partners, suppliers and customers to perform their contractual obligations may be affected by economic impacts related to COVID-19.

Emera manages this counterparty risk through contractual rights and remedies, regulatory frameworks and by monitoring significant developments with its customers, partners and suppliers. The Company also manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments may be conducted on new customers and counterparties, and deposits or collateral may be requested on certain accounts. Emera may also seek recovery of unpaid amounts or damages through applicable bankruptcy, insolvency or similar proceedings.

Country Risk

Earnings outside of Canada constituted 73 per cent of Emera's earnings in 2020 (2019 – 61 per cent) with the majority from the US. Emera's investments are currently in regions where political and economic risks are considered by the Company to be acceptable. Emera's operations in some countries may be subject to changes in economic growth, restrictions on the repatriation of income or capital exchange controls, inflation, the effect of global health, safety and environmental matters, including climate change, or economic conditions and market conditions, and change in financial policy and availability of credit. The Company mitigates this risk through a rigorous approval process for investment, and by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available in all affiliates.

Commodity Price Risk

The Company's utility fuel supply is subject to commodity price risk. In addition, Emera Energy is subject to commodity price risk through its portfolio of commodity contracts and arrangements.

The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. The Company's commercial arrangements, including the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements and financial hedging instruments are all used to manage and mitigate this risk. In addition, its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are also used to manage and mitigate this risk.

Regulated Utilities

A large portion of the Company's utility fuel supply comes from international suppliers and therefore may be exposed to broader global conditions, which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk using financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable.

The majority of Emera's regulated utilities have adopted and implemented fuel adjustment mechanisms which has further helped manage commodity price risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

Emera Energy Marketing and Trading

Emera Energy has employed further measures to manage commodity risk. The majority of Emera's portfolio of electricity and gas marketing and trading contracts and, in particular, its natural gas asset management arrangements, are contracted on a back-to-back basis, avoiding any material long or short commodity positions. However, the portfolio is subject to commodity price risk, particularly with respect to basis point differentials between relevant markets, in the event of an operational issue or counterparty default.

To measure commodity price risk exposure, Emera employs a number of controls and processes, including an estimated VaR analysis of its exposures. The VaR amount represents an estimate of the potential change in fair value that could occur from changes in market factors within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with physical commodities, primarily natural gas and power positions.

Future Employee Benefit Plan Performance and Funding Risk

Emera subsidiaries have both defined benefit and defined contribution employee pension plans that cover their employees and retirees. All defined benefit plans are closed to new entrants, except for the TECO Energy Group Retirement Plan. The cost of providing these benefit plans varies depending on plan provisions, interest rates, investment performance and actuarial assumptions concerning the future. The COVID-19 pandemic could have an impact on key actuarial assumptions. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels, contributions to the plans and the pension and post-retirement liabilities) and expectations around future salary growth, inflation and mortality. Two of the largest drivers of cost are investment performance and interest rates, which are affected by global financial and capital markets. Depending on future interest rates and actual versus expected investment performance, Emera could be required to make larger contributions in the future to fund these plans, which could affect Emera's cash flows, financial condition and operations.

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

Labour Risk

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

Approximately 35 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have an adverse effect on the Company's earnings, cash flow and financial position. Emera seeks to manage this risk through ongoing discussions and working to maintain positive relationships with local unions. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labour disruption.

Information Technology Risk

Emera relies on various information technology systems to manage operations. This subjects Emera to inherent costs and risks associated with maintaining, upgrading, replacing and changing these systems. This includes impairment of its information technology, potential disruption of internal control systems, substantial capital expenditures, demands on management time and other risks of delays, difficulties in upgrading existing systems, transitioning to new systems or integrating new systems into its current systems. Emera's digital transformation strategy, including investment in infrastructure modernization and customer focused technologies, is driving increased investment in information technology solutions, resulting in increased project risks associated with the implementation of these solutions.

Emera manages these information technology risks through IT asset lifecycle planning and management, governance, internal auditing and testing of systems, and executive oversight. Employees with extensive subject matter expertise assist in risk identification and mitigation, project management, implementation, change management and training. System resiliency, formal disaster recovery and backup processes, combined with critical incident response practices, ensure that continuity is maintained in the event of any disruptions.

Income Tax Risk

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

System Operating and Maintenance Risks

The safe and reliable operation of electric generation and electric and natural gas transmission and distribution systems is critical to Emera's operations. There are a variety of hazards and operational risks inherent in operating electric utilities and natural gas transmission and distribution pipelines. Electric generation, transmission and distribution operations can be impacted by risks such as mechanical failures, activities of third parties, damage to facilities, solar panels and infrastructure caused by hurricanes, storms, falling trees, lightning strikes, floods, fires and other natural disasters. Natural gas pipeline operations can be impacted by risks such as leaks, explosions, mechanical failures, activities of third parties and damage to the pipelines facilities and equipment caused by hurricanes, storms, floods, fires and other natural disasters. Refer to "Global Climate Change Risk" and "Weather Risk". Electric utility and natural gas transmission and distribution pipeline operation interruption could negatively affect revenue, earnings, and cash flows as well as customer and public confidence.

Emera manages these risks by investing in a highly skilled workforce, operating prudently, preventative maintenance and making effective capital investments. Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all these losses, which could adversely affect the Company's results of operations and cash flows.

Uninsured Risk

Emera and its subsidiaries maintain insurance to cover accidental loss suffered to its facilities and to provide indemnity in the event of liability to third parties. This is consistent with Emera's risk management policies. Certain facilities, in particular coal and other thermal generation, may, over time, become more difficult (or uneconomic) to insure as a result of the impact of global climate change. Refer to "Global Climate Change Risk – Markets". There are certain elements of Emera's operations which are not insured. These include a significant portion of its electric utilities' transmission and distribution assets, as is customary in the industry. The cost of this coverage is not economically viable. In addition, Emera accepts deductibles and self-insured retentions under its various insurance policies. Insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities or losses that may be incurred by the Company and its subsidiaries will be covered by insurance.

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

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

RISK MANAGEMENT INCLUDING FINANCIAL INSTRUMENTS

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

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

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

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge the identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, the change in the fair value of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized. Where the documentation or effectiveness requirements are not met any changes in fair value are recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

Derivatives entered into by NSPI, NMGC and GBPC that are documented as economic hedges, and for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled in regulated fuel for generation and purchased power, inventory or property, plant and equipment, depending on the nature of the item being economically hedged. Management believes any gains or losses resulting from settlement of these derivatives will be refunded to or collected from customers in future rates. Tampa Electric and PGS have no derivatives related to hedging as a result of a Florida Public Service Commission approved five-year moratorium on hedging of natural gas purchases which ends on December 31, 2022.

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

Hedging Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**December 31 2020**		December 31 2019
Derivative instrument assets (current and other assets)	**$**	**1**	$	-
Derivative instrument liabilities (current and long-term liabilities)		**-**		(1)
Net derivative instrument assets (liabilities)	**$**	**1**	$	(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				Year ended December 31
		2020		2019
Operating revenues – regulated	**$**	**(2)**	$	(3)
Effective net losses	**$**	**(2)**	$	(3)

The effective net losses reflected in the above table are offset in net income by the hedged item realized in the period.

Regulatory Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**December 31 2020**		December 31 2019
Derivative instrument assets (current and other assets)	**$**	**14**	$	28
Regulatory assets (current and other assets)		**65**		80
Derivative instrument liabilities (current and long-term liabilities)		**(62)**		(78)
Regulatory liabilities (current and long-term liabilities)		**(15)**		(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		Year ended **2020**		December 31 2019
Regulated fuel for generation and purchased power (1)	**$**	**(21)**	$	5
Net gains (losses)	**$**	**(21)**	$	5

(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		**December 31 2020**		December 31 2019
Derivative instrument assets (current and other assets)	**$**	**68**	$	58
Derivative instrument liabilities (current and long-term liabilities)		**(275)**		(291)
Net derivative instrument liability	**$**	**(207)**	$	(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				Year ended December 31
		2020		2019
Non-regulated operating revenues	**$**	**204**	$	282
Non-regulated fuel for generation and purchased power		**(4)**		(6)
Net gains	**$**	**200**	$	276

Other Derivatives Recognized on the Balance Sheets

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

As at millions of Canadian dollars		**December 31 2020**		December 31 2019
Derivative instrument assets (current and other assets)	**$**	**15**	$	1
Derivative instrument liabilities (current and long-term liabilities)		**(1)**		-
Net derivative instrument assets	**$**	**14**	$	1

Other Derivatives Recognized in Net Income

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

For the millions of Canadian dollars				Year ended December 31
		2020		2019
Operating, maintenance and general	**$**	**(4)**	$	28
Other income, net		**13**		-
Net gains	**$**	**9**	$	28

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures (“DC&P”) and internal control over financial reporting (“ICFR”), as defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”). The Company’s internal control framework is based on the criteria published in the Internal Control - Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations (“COSO”) of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design and effectiveness of the Company’s DC&P and ICFR as at December 31, 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 year ended December 31, 2020, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

Preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect 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 use of management estimates relate to rate-regulated assets and liabilities, allowance for credit losses, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations, and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized through income in the year they arise.

During the year ended December 31, 2020, the ongoing COVID-19 pandemic has affected all service territories in which Emera operates. 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 on 2020 net earnings. This was primarily due to a favourable change to the mix of sales across customer classes resulting in the lower commercial and industrial sales being partially offset by increased sales to residential customers, which have a higher contribution to fixed cost recovery. Favourable weather in 2020, in particular in Florida, has further reduced the consolidated impact. Emera's utilities provide essential services and continue to operate and meet customer demand. 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. In addition, Global equity markets have experienced significant volatility. 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.

Management has analyzed the impact of the COVID-19 pandemic on its estimates and judgments and concluded that no material adjustments were required at December 31, 2020. The extent of the future impact of COVID-19 on the Company's financial results and business operations cannot be predicted and will depend on future developments, including duration and severity of the pandemic, timing and effectiveness of vaccinations, further potential government actions and future economic activity and energy usage. Actual results may differ significantly from these estimates.

Rate Regulation

The rate-regulated accounting policies of Emera's rate-regulated subsidiaries and regulated equity investments are subject to examination and approval by their respective regulators and may differ from accounting policies for non-rate-regulated companies. These accounting policy differences occur when the regulators render their decisions on rate applications or other matters, and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on expectations of the future actions of the regulators. Assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered. The application of regulatory accounting guidance is a critical accounting policy as a change in these assumptions may result in a material impact on reported assets, liabilities and the results of operations.

The Company has recorded $1,584 million (2019 - $1,552 million) of regulatory assets and $1,961 million (2019 - $2,181 million) of regulatory liabilities as at December 31, 2020.

Accumulated Reserve – Cost of Removal

Tampa Electric, PGS, NMGC and NSPI recognize non-asset retirement obligation costs of removal as regulatory liabilities. These costs of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required costs of removal of property, plant and equipment upon retirement. The companies accrue for costs of removal over the life of the related assets based on depreciation studies approved by their respective regulators. Costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays. The balance of the Accumulated reserve – cost of removal within regulatory liabilities was $866 million at December 31, 2020 (2019 - $891 million).

Pension and Other Post-Retirement Employee Benefits

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

The accounting related to employee post-retirement benefits is a critical accounting estimate. Changes in the estimated benefit obligation, affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings, could have a material impact on reported assets, liabilities, accumulated other comprehensive income and results of operations. The COVID-19 pandemic could have an impact on key actuarial assumptions. Changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs could change annual funding requirements. This could have a significant impact on the Company's annual earnings and cash requirements.

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

The Company's accounting policy is to amortize the net actuarial gain or loss, that exceeds 10 per cent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period. For the largest plans this is currently 9.4 years (9.8 years for 2020 benefit cost) for the Canadian plans and a weighted average of 12.1 years for the US plans). The Company's use of smoothed asset values reduces volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

The discount rate used to determine benefit costs is based on the yield of high quality long-term corporate bonds in each operating entity's country and is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year. The following table shows the discount rate for benefit cost purposes and the expected return on plan assets for each plan:

	2020		2019	
	Discount rate for benefit cost purposes	**Expected return on plan assets**	Discount rate for benefit cost purposes	Expected return on plan assets
TECO Energy Group Retirement Plan	**3.22%**	**7.00%**	4.34 % / 3.13 %	7.35 / 7.00
TECO Energy Group Supplemental Executive Retirement Plan (1)	**2.78%**	**N/A**	4.02 **%**	N/A
TECO Energy Group Benefit Restoration Plan (1)	**2.81%**	**N/A**	4.12 / 3.94 / 3.32 %	N/A
TECO Energy Post-retirement Health and Welfare Plan	**3.32%**	**N/A**	4.38 %	N/A
New Mexico Gas Company Retiree Medical Plan	**3.32%**	**3.25%**	4.39 %	3.25 %
NSPI	**3.13%, 3.21%**	**5.75%**	3.83 %	6.00 %
GBPC Salaried	**4.25%**	**6.00%**	4.25 %	6.00 %
GBPC Union	**5.00%**	**5.00%**	5.00 %	5.00 %

(1) The discount rate and expected return on assets for benefit cost purposes is updated throughout the year as special events occur, such as settlements and curtailments.
(2) On March 24, 2020, Emera completed the sale of Emera Maine. The discount rate for benefit cost purposes and expected return on plan assets up until the time of sale was 3.18% (2019- 4.19%) and 6.35% (2019 – 6.35%) for Bangor Hydro and 3.09% (2019 - 4.12%) and 6.55% (2019 – 6.55%) for Maine Public Service.

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans was $87 million in 2020 (2019 - $84 million). The reported benefit cost is impacted by numerous assumptions, including the discount rate and asset return assumptions. A 0.25 per cent change in the discount rate and asset return assumptions would have had +/- impact on the 2020 benefit cost of $6 million and $5 million respectively (2019 - $9 million and $6 million).

Unbilled Revenue

Electric and gas revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for other Emera utilities. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and determine related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses, inter-period changes to customer classes and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2020, unbilled revenues totalled $286 million (2019 – $265 million) on total regulated operating revenues of $5,476 million (2019 – $5,850 million).

Property, Plant and Equipment

Property, plant and equipment represents 63 per cent of total assets on the Company's balance sheet. Included in "Property, plant and equipment" are the generation, transmission and distribution and other assets of the Company.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated property, plant and equipment are determined based on depreciation studies and require appropriate regulatory approval. Due to the magnitude of the Company's property, plant and equipment, changes in estimated depreciation rates can have a material impact on depreciation expense and accumulated depreciation.

Depreciation expense was $860 million for the year ended December 31, 2020 (2019 – $881 million).

Goodwill Impairment Assessments

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

If the Company performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, or if the Company chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Significant assumptions used in estimating the fair value include discount and growth rates, rate case assumptions, valuation of the reporting units' net operating loss ("NOL"), utility sector market performance and transactions, projected operating and capital cash flows and the fair value of debt. As part of the 2020 goodwill impairment assessment management considered potential impacts of the COVID-19 pandemic on future earnings of the reporting units.

As of December 31, 2020, the Company had goodwill with a total carrying amount of $5,720 million (December 31, 2019 – $5,835 million). This goodwill represents the excess of the acquisition purchase price for TECO Energy (Tampa Electric, PGS and NMGC reporting units) and GBPC over the fair values assigned to identifiable assets acquired and liabilities assumed. The change in the carrying value of goodwill from 2019 to 2020 was a result of the strengthening Canadian dollar on the goodwill balances.

As of December 31, 2020, $5,649 million of Emera's goodwill was related to TECO Energy (Tampa Electric, PGS and NMGC reporting units). A qualitative assessment was performed for these reporting units given the significant excess of fair value over carrying amounts calculated during the last quantitative test in Q4 2019. Management concluded that it was more likely than not that the fair value of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required.

A GBPC goodwill impairment charge of $30 million was recorded in 2019 due to a decrease in expected future cash flows resulting from the impacts of Hurricane Dorian storm recovery and changes in the anticipated long term regulated capital structure of GBPC. As of December 31, 2020, $68 million of Emera's goodwill was related to GBPC. In Q4 2020, the Company performed a quantitative impairment assessment for GBPC as this reporting unit is more sensitive to changes in forecasted future earnings due to limited excess of fair value over the carrying value. The assessment estimated that the fair value of the reporting unit exceeded its carrying value, including goodwill, by approximately five per cent. Adverse changes in significant assumptions could result in a future impairment. For further detail, refer to note 22 to the consolidated financial statements.

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

Long-Lived Assets Impairment Assessments

In accordance with accounting guidance for long-lived assets, the Company assesses whether there has been an impairment of long-lived assets and intangibles when a triggering event occurs, such as a significant market disruption or the sale of a business. Review of long-lived assets for impairment involves comparing the undiscounted expected future cash flows to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated fair value.

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

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 December 31, 2020, there were 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.

In Q1 2020, impairment charges of $25 million ($26 million after tax) were recognized on certain assets and recorded in Impairment Charge on the Consolidated Income Statement. In 2019, as a result of Hurricane Dorian, Grand Bahama recognized an impairment of $18 million USD which has been fully recovered through insurance.

Income Taxes

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

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

Asset Retirement Obligations ("ARO")

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

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

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

As at December 31, 2020, AROs recorded on the balance sheet were $178 million (2019 – $185 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $432 million (2019 - $422 million), which will be incurred between 2021 and 2061. The majority of these costs will be incurred between 2028 and 2050.

Financial Instruments

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

Level Determinations and Classifications

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

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 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. These include 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 consolidated financial statements as of January 1, 2020.

Simplifying the Accounting for Income Taxes

In December 2019, the FASB issued ASU 2019-12, Simplifying the Accounting for Income Taxes. The standard simplifies the accounting for income taxes by eliminating certain exceptions to the guidance in ASC 740 related to the approach for intraperiod tax allocation. It also simplifies aspects of accounting for franchise taxes and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. The guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2020, with early adoption permitted. The standard is applied on both a prospective and retrospective basis. The Company early adopted the standard effective January 1, 2020. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

Facilitation of the Effects of Reference Rate Reform on Financial Reporting

The Company adopted ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting* in Q4 2020. The standard provides options and exceptions for applying USGAAP to contract modifications and hedging relationships that reference the London Inter-Bank Offered Rate ("LIBOR") or any other reference 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's transition from reference rates will not have a material impact on the consolidated financial statements. In November 2020, the Federal Reserve extended the phase-out of LIBOR until June 2023. The Company will continue to monitor the impact this may have on application of the standard.

Future Accounting Pronouncements

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

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 simplifies the accounting 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 can be applied through either a modified retrospective method of transition or a fully retrospective method of transition. The Company early adopted the standard effective January 1, 2021 using the modified retrospective method. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

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 disclosure, 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)	**Q4 2020**	Q3 2020	Q2 2020	Q1 2020	Q4 2019	Q3 2019	Q2 2019	Q1 2019
Operating revenues	**$ 1,537**	$ 1,163	$ 1,169	$ 1,637	$ 1,616	$ 1,299	$ 1,378	$ 1,818
Net income attributable to common shareholders	**273**	84	58	523	193	55	103	312
Adjusted net income attributable to common shareholders	**188**	166	118	193	145	122	130	224
Earnings per common share – basic	**1.09**	0.34	0.24	2.14	0.79	0.23	0.43	1.32
Earnings per common share – diluted	**1.08**	0.34	0.23	2.13	0.80	0.23	0.43	1.32
Adjusted earnings per common share – basic	**0.75**	0.67	0.48	0.79	0.60	0.51	0.54	0.95

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. For further detail, refer to the "Business Overview and Outlook" section.