Management's Discussion & Analysis

As at November 10, 2022

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments during the third quarter and year-to-date of 2022 relative to the same periods in 2021; and its financial position as at September 30, 2022 relative to December 31, 2021. Throughout this discussion, "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, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

This discussion and analysis should be read in conjunction with the Emera unaudited condensed consolidated interim financial statements and supporting notes as at and for the three and nine months ended September 30, 2022; and the Emera annual MD&A and audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2021. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP").

The accounting policies used by Emera's rate-regulated entities may differ from those used by Emera's non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. At September 30, 2022, Emera's rate-regulated subsidiaries and investments include:

Emera Rate-Regulated Subsidiary or Equity	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")
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")
Barbados Light & Power Company Limited ("BLPC")	Fair Trading Commission, Barbados ("FTC")
Grand Bahama Power Company Limited ("GBPC")	The Grand Bahama Port Authority ("GBPA")
Equity Investments	
NSP Maritime Link Inc. ("NSPML")	UARB
Labrador Island Link Limited Partnership ("LIL")	Newfoundland and Labrador Board of Commissioners of Public Utilities ("NLPUB")
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline, LLC ("M&NP")	CER and FERC
St. Lucia Electricity Services Limited ("Lucelec")	National Utility Regulatory Commission ("NURC")

All amounts are in Canadian dollars ("CAD"), except for the Florida Electric Utility, Gas Utilities and Infrastructure, and Other Electric Utilities 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 dioxide 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 investments; 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 (“FX”); 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 electric and gas services in designated territories under franchises and are overseen by regulatory authorities. Emera's strategic focus continues to be safely delivering 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 capital investment plan is $8 – 9 billion over the 2023-to-2025 period (including a $240 million equity investment in the LIL in 2023). This results in a forecasted rate base growth of approximately 7 per cent to 8 per cent through 2025. The capital investment plan continues to include significant investments across the portfolio in renewable and cleaner generation, reliability and integrity investments, 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 are expected to be funded through the issuance of preferred equity and the issuance of common equity through Emera's dividend reinvestment plan and at-the-market program ("ATM program"). Maintaining investment-grade credit ratings is a priority of management.

Emera has provided annual dividend growth guidance of four to five per cent through 2025. The Company targets a long-term dividend payout ratio of adjusted net income 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. For further information on the non-GAAP measure "Dividend Payout Ratio of Adjusted Net Income", refer to the "Non-GAAP Financial Measures and Ratios" section.

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 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 of 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, and the ongoing construction of solar generation and 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 dioxide 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 dioxide emissions by 2025.
- The retirement of Emera's last existing coal unit no later than 2040.
- An 80 per cent reduction in carbon dioxide emissions by 2040.

Emera seeks to deliver on its Climate Commitment while maintaining its focus on investing in reliability and staying focused on the cost impacts for customers. Emera is also committed to identifying emerging technologies and continuing to work constructively with policymakers, regulators, partners, investors and customers to achieve these goals and realize its net-zero vision.

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 AND RATIOS

Emera uses financial measures and ratios 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 and ratios by adjusting certain GAAP measures for specific items. Management believes excluding these items better distinguishes the ongoing operations of the business and allows investors to better understand and evaluate the business. These measures and ratios are discussed and reconciled below.

Adjusted Net Income Attributable to Common Shareholders, Adjusted Earnings Per Common Share – Basic and Dividend Payout Ratio of Adjusted Net Income.

Emera calculates an adjusted net income attributable to common shareholders ("adjusted net income") measure by excluding the effect of mark-to-market ("MTM") adjustments and the impact of the NSPML unrecoverable costs.

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 excludes these MTM adjustments for evaluation of performance and incentive compensation. The MTM adjustments are related to the following:

- 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, and the related amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the business activities of Bear Swamp Power Company LLC ("Bear Swamp") included in Emera's equity income;
- equity securities held in BLPC and a captive reinsurance company in the Other segment; and
- FX cash flow hedges entered to manage FX earnings exposure.

For further detail on MTM adjustments, refer to the "Consolidated Financial Review", "Financial Highlights – Other Electric Utilities", and "Financial Highlights – Other" sections.

In February 2022, the UARB issued a decision to disallow the recovery of $9 million in costs ($7 million after-tax) included in NSPML's final capital cost application. The after-tax unrecoverable costs were recognized in "Income from equity investments" in Emera's Condensed Consolidated Statements of Income. Management believes excluding these unrecoverable costs from the calculation of adjusted net income better reflects the underlying operations in the period. For further details on the NSPML unrecoverable costs, refer to the "Business Overview and Outlook – Canadian Electric Utilities" and "Financial Highlights – Canadian Electric Utilities" sections.

Adjusted earnings per common share – basic and dividend payout ratio of adjusted net income are non-GAAP ratios which are calculated using adjusted net income, as described above.

Emera calculates adjusted net income and adjusted earnings per common share – basic for the Canadian Electric Utilities, Other Electric Utilities, and Other segments. Reconciliation to the nearest GAAP measure is included in each segment. Refer to "Financial Highlights – Canadian Electric Utilities", "Financial Highlights – Other Electric Utilities" and "Financial Highlights – Other" sections. For further details on dividend payout ratio of adjusted net income, see the "Dividend Payout Ratio" section in Emera's 2021 annual MD&A.

The following reconciles net income (loss) attributable to common shareholders to adjusted net income:

For the millions of dollars (except per share amounts)	Three months ended September 30 **2022**	 2021	Nine months ended September 30 **2022**	 2021
Net income (loss) attributable to common shareholders	**$ 167**	$ (70)	**$ 462**	$ 186
MTM loss, after-tax (1)	**(36)**	(245)	**(132)**	(369)
NSPML unrecoverable costs (2)	**-**	-	**(7)**	-
Adjusted net income	**$ 203**	$ 175	**$ 601**	$ 555
Earnings (loss) per common share – basic	**$ 0.63**	$ (0.27)	**$ 1.75**	$ 0.73
Adjusted earnings per common share – basic	**$ 0.76**	$ 0.68	**$ 2.27**	$ 2.17

(1) Net of income tax recovery of $14 million for the three months ended September 30, 2022 (2021 - $100 million recovery) and $51 million recovery for the nine months ended September 30, 2022 (2021 - $149 million recovery).
(2) Emera accounts for NSPML as an equity investment and therefore the after-tax unrecoverable costs were recorded in "Income from equity investments" on Emera's Condensed Consolidated Statements of Income.

EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") and adjusted EBITDA are non-GAAP financial measures used by Emera. These financial measures are 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.

Similar to adjusted net income calculations described above, adjusted EBITDA represents EBITDA absent the income effect of MTM adjustments and the NSPML unrecoverable costs.

The following is a reconciliation of net income (loss) to EBITDA and Adjusted EBITDA:

For the millions of dollars	Three months ended September 30 2022	 2021	Nine months ended September 30 2022	 2021
Net income (loss) (1)	**$ 184**	$ (56)	**$ 510**	$ 223
Interest expense, net	**184**	150	**503**	460
Income tax expense (recovery)	**2**	(92)	**31**	(91)
Depreciation and amortization	**238**	228	**698**	675
EBITDA	**$ 608**	$ 230	**$ 1,742**	$ 1,267
MTM loss, excluding income tax	**(50)**	(345)	**(183)**	(518)
NSPML unrecoverable costs (2)	**-**	-	**(7)**	-
Adjusted EBITDA	**$ 658**	$ 575	**$ 1,932**	$ 1,785

(1) Net income (loss) is before Non-controlling interest in subsidiaries and Preferred stock dividends.
(2) Emera accounts for NSPML as an equity investment and therefore the after-tax unrecoverable costs were recorded in “Income from equity investments” on Emera’s Condensed Consolidated Statements of Income.

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

Earnings Impact of MTM Loss, After-Tax

MTM loss, after-tax decreased $209 million to $36 million in Q3 2022, compared to $245 million in Q3 2021 primarily due to changes in existing positions, partially offset by higher amortization of gas transportation assets in 2022 and larger reversal of MTM losses in 2021 at Emera Energy. Year-to-date, MTM loss, after-tax decreased $237 million to $132 million compared to $369 million for the same period in 2021 due to a larger reversal of MTM losses in 2022 and changes in existing positions, partially offset by higher amortization of gas transportation assets in 2022 at Emera Energy.

Consolidated Financial Highlights

For the millions of dollars **Adjusted net income**	Three months ended September 30 2022	 2021	Nine months ended September 30 2022	 2021
Florida Electric Utility	**$ 199**	$ 169	**$ 472**	$ 377
Canadian Electric Utilities	**39**	42	**176**	174
Gas Utilities and Infrastructure	**33**	29	**149**	143
Other Electric Utilities	**12**	8	**21**	15
Other	**(80)**	(73)	**(217)**	(154)
Adjusted net income	**$ 203**	$ 175	**$ 601**	$ 555
MTM loss, after-tax	**(36)**	(245)	**(132)**	(369)
NSPML unrecoverable costs	**-**	-	**(7)**	-
Net income (loss) attributable to common shareholders	**$ 167**	$ (70)	**$ 462**	$ 186

The following table highlights significant changes in adjusted net income from 2021 to 2022:

For the millions of dollars		Three months ended September 30		Nine months ended September 30
Adjusted net income – 2021	**$**	**175**	**$**	**555**
Operating Unit Performance				
Increased earnings at Tampa Electric due to higher revenues as a result of rate increases effective January 2022, customer growth and the impact of a weakening CAD. These were partially offset by higher operating, maintenance and general expenses ("OM&G"), increased interest expense and higher depreciation. Year-over-year also increased due to favourable weather		30		95
Increased earnings at NSPI driven by higher sales volumes, partially offset by increased OM&G primarily due to increased information technology, storm restoration and power generation expenses		2		10
Increased earnings at PGS due to reversal of accumulated depreciation as a result of the rate case settlement and higher off-system sales, partially offset by higher OM&G. Year-over-year also increased due to customer growth		3		8
Increased earnings at Seacoast due to commencement of a 34-year pipeline lateral lease in 2022		2		6
Increased earnings at Emera Energy Services ("EES") due to higher natural gas prices and volatility, which created profitable opportunities. Year-over-year increase was offset by the positive margin impact of Winter Storm Uri in Q1 2021		16		-
Corporate				
Increased OM&G, pre-tax due to the timing of long-term compensation and related hedges		(17)		(36)
Increased FX loss, pre-tax, primarily due to realized gains in 2021 on FX hedges entered into to hedge USD denominated operating unit earnings exposure		(6)		(19)
Increased preferred stock dividends due to issuance of preferred shares in 2021		(2)		(11)
Increased interest expense, pre-tax, due to higher interest rates and increased total debt		(10)		(10)
Other Variances		10		3
Adjusted net income – 2022	**$**	**203**	**$**	**601**

For further details of reportable segments contributions, refer to the "Financial Highlights" section.

For the millions of dollars	Nine months ended September 30 **2022**			2021
Operating cash flow before changes in working capital	**$**	**806**	$	1,035
Change in working capital		**149**		71
Operating cash flow	**$**	**955**	$	1,106
Investing cash flow	**$**	**(1,685)**	$	(1,576)
Financing cash flow	**$**	**844**	$	693

For further discussion of cash flow, refer to the "Consolidated Cash Flow Highlights" section.

As at millions of dollars		**September 30 2022**		December 31 2021
Total assets	**$**	**39,804**	$	34,244
Total long-term debt (including current portion)	**$**	**15,860**	$	14,658

Consolidated Income Statement Highlights

For the millions of dollars (except per share amounts)		Three months ended September 30 **2022**		2021		Variance		Nine months ended September 30 **2022**		2021		Variance
Operating revenues	**$**	**1,835**	$	1,148	$	687	**$**	**5,230**	$	3,897	$	1,333
Operating expenses		**1,496**		1,201		(295)		**4,321**		3,483		(838)
Income from operations	**$**	**339**	$	(53)	$	392	**$**	**909**	$	414	$	495
Net income (loss) attributable to common shareholders	**$**	**167**	$	(70)	$	237	**$**	**462**	$	186	$	276
Adjusted net income	**$**	**203**	$	175	$	28	**$**	**601**	$	555	$	46
Weighted average shares of common stock outstanding (in millions) (1)		**266.6**		258.5		8.1		**264.3**		256.0		8.3
Earnings (loss) per common share – basic	**$**	**0.63**	$	(0.27)	$	0.90	**$**	**1.75**	$	0.73	$	1.02
Earnings (loss) per common share – diluted	**$**	**0.63**	$	(0.27)	$	0.90	**$**	**1.74**	$	0.73	$	1.01
Adjusted earnings per common share – basic	**$**	**0.76**	$	0.68	$	0.08	**$**	**2.27**	$	2.17	$	0.10
Dividends per common share	**$**	**0.6625**	$	0.6375	$	0.0250	**$**	**1.9875**	$	1.9125	$	0.0750
Adjusted EBITDA	**$**	**658**	$	575	$	83	**$**	**1,932**	$	1,785	$	147

(1) Effective February 10, 2022, deferred share units are no longer able to be settled in shares and are therefore excluded from weighted average shares of common stock outstanding.

Operating Revenues

For Q3 2022, operating revenues increased $687 million compared to Q3 2021 and, absent decreased MTM losses of $317 million, increased $370 million. Year-to-date 2022, operating revenues increased $1,333 million compared to 2021 and, absent decreased MTM losses of $360 million, increased by $973 million. The increases in both periods were due to higher fuel revenues at NMGC, Tampa Electric, PGS, and BLPC, new rates effective January 2022 and customer growth at Tampa Electric, the impact of a weaker CAD, increased sales volumes at NSPI, higher off-system sales at PGS, and increased marketing and trading margin at EES. Favourable weather at Tampa Electric and customer growth at PGS contributed to increased operating revenues year-over-year, partially offset by the margin impact at EES of Winter Storm Uri in Q1 2021.

Operating Expenses

For Q3 2022, operating expenses increased $295 million and year-to-date 2022, increased $838 million compared to the same periods in 2021. The increases in both periods were due to higher natural gas and fuel prices at the regulated utilities, the impact of a weaker CAD and increased OM&G at Tampa Electric, Corporate and NSPI.

Net Income and Adjusted Net Income

For Q3 2022, net income attributable to common shareholders compared to Q3 2021, was favourably impacted by the $209 million decrease in after-tax MTM losses. Absent the favourable MTM changes, adjusted net income increased $28 million. The increase was primarily due to higher earnings contribution from Tampa Electric and Emera Energy and the impact of a weaker CAD. These were partially offset by increased OM&G at Corporate due to the timing of long-term compensation and related hedges and higher interest expense due to higher interest rates and increased total debt.

Year-to-date 2022, net income attributable to common shareholders, compared to the same period in 2021, was favourably impacted by the $237 million decrease in after-tax MTM losses and unfavourably impacted by the $7 million in NSPML unrecoverable costs. Absent these changes, adjusted net income increased $46 million. The increase was primarily due to higher earnings contributions from Tampa Electric, NSPI, PGS and Seacoast and the impact of a weaker CAD. These were partially offset by increased Corporate OM&G due to the timing of long-term compensation and related hedges, realized gains on Corporate cash flow hedges in 2021, increased preferred stock dividends and increased interest expense due to higher interest rates and increased total debt.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings and adjusted earnings per common share – basic were higher for Q3 2022, and year-to-date 2022, due to the impact of higher earnings as discussed above, partially offset by the impact of the increase in weighted average shares of common stock outstanding.

Effect of Foreign Currency Translation

Emera operates in Canada, the United States and various Caribbean countries and, as such, 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.

In general, Emera's earnings benefit from a weakening CAD and are adversely impacted by a strengthening CAD. The impact in any period is driven by rate changes, the timing and percentage of earnings from foreign operations, and the impact of entered FX cash flow hedges to manage FX 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 2022 and 2021 are as follows:

For the	Three months ended September 30 **2022**	2021	Nine months ended September 30 **2022**	2021	Year ended December 31 2021
Weighted average CAD/USD	**$ 1.35**	$ 1.28	**$ 1.30**	$ 1.27	$ 1.26
Period end CAD/USD	**$ 1.37**	$ 1.27	**$ 1.37**	$ 1.27	$ 1.27

The table below includes Emera's significant segments whose contributions to adjusted net income are recorded in USD currency.

For the millions of USD	Three months ended September 30 **2022**	2021	Nine months ended September 30 **2022**	2021
Florida Electric Utility	**$ 153**	$ 135	**$ 367**	$ 302
Gas Utilities and Infrastructure (1)	**19**	16	**98**	93
Other Electric Utilities	**9**	6	**16**	12
Other segment (2)	**(30)**	(39)	**(80)**	(78)
Total (3)	**$ 151**	$ 118	**$ 401**	$ 329

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's USD adjusted net income from EES, Bear Swamp and interest expense on Emera Inc.'s USD denominated debt.
(3) Net of $22 million MTM loss, after-tax for the three months ended September 30, 2022 (2021 - $190 million) and $92 million MTM loss, after-tax, for the nine months ended September 30, 2022 (2021 - $286 million).

The impact of the unrealized losses on FX hedges, partially offset by weakening of the CAD decreased net income by $12 million in Q3 2022 and year-to-date 2022, compared to the same periods in 2021. Weakening of the CAD increased adjusted net income by $7 million in Q3 2022 and $14 million year-to-date 2022, compared to the same periods in 2021. The impacts of the weakening CAD include the current quarter and year-to-date impacts of corporate FX hedges in the Other segment.

BUSINESS OVERVIEW AND OUTLOOK

COVID-19 Pandemic

The Company's priorities continue to be reliable delivery of essential energy services to meet customers' demands while maintaining the health and safety of its customers and employees and supporting the communities in which Emera operates. While the ongoing COVID-19 pandemic has had varying effects on the service territories in which Emera operates, on a consolidated basis, COVID-19 is not expected to have a material financial impact in 2022. For further information on COVID-19 and its potential future impacts on Emera and its businesses, refer to the "Business Overview and Outlook" and "Liquidity and Capital Resources" sections in Emera's 2021 annual MD&A.

Florida Electric Utility

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

Tampa Electric anticipates earning within its ROE range in 2022. New base rates effective January 1, 2022 are expected to result in higher 2022 USD earnings than in 2021. Tampa Electric expects customer growth rates in 2022 to be consistent with 2021, reflective of current economic growth in Florida.

Tampa Electric's 2021 settlement agreement allows the company to request an increase to revenue and ROE due to increases in the 30-year United States Treasury bond yield rate. On July 1, 2022, Tampa Electric requested the FPSC to increase its annual base rates by $10 million USD effective September 1, 2022 and to increase its ROE. On August 16, 2022, the FPSC approved the change. Effective July 1, 2022, the new mid-point ROE is 10.20 per cent, and the range is 9.25 per cent to 11.25 per cent.

The mid-course fuel adjustment requested by Tampa Electric on January 19, 2022, was approved on March 1, 2022. The rate increase, effective with the first billing cycle in April 2022, covered higher fuel and capacity costs of $169 million USD and will be spread over customer bills from April 1, 2022 through December 2022. Tampa Electric continues to be impacted by increased fuel costs and expects to have an under-recovered fuel balance at the end 2022. Tampa Electric plans to file for recovery of this balance in late 2022 or early 2023 for collection in subsequent periods.

On September 28, 2022, Hurricane Ian made landfall in Southwest Florida as a Category 4 hurricane and as a result, approximately 291,000 customers lost power. The majority of Hurricane Ian restoration costs will be charged against Tampa Electric's FPSC approved storm reserve, resulting in minimal impact to earnings for 2022. The total cost of restoration is estimated to be $130 million USD. As of September 30, 2022, Tampa Electric incurred $68 million USD in storm restoration cost and an additional $62 million USD in storm restoration costs are expected to be incurred in Q4 2022. Total restoration costs charged to the storm reserve have exceeded the reserve balance and have been deferred as a regulatory asset for future recovery. Tampa Electric expects to petition the FPSC in late 2022 or early 2023 for recovery of the storm reserve regulatory asset and the replenishment of the balance in the reserve to the previous approved reserve level of $56 million USD, for a total of approximately $136 million USD.

In 2022, capital investment in the Florida Electric Utility segment is expected to be approximately $1.1 billion USD (2021 - $1.2 billion USD), including allowance for funds used during construction ("AFUDC"). Capital projects include continuation of the modernization of the Big Bend Power Station, solar investments, grid modernization, storm hardening investments, and operational infrastructure.

Canadian Electric Utilities

Canadian Electric Utilities includes NSPI and Emera Newfoundland & Labrador Holdings Inc. ("ENL"). NSPI is a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and is 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

NSPI anticipates earning near the low end of its allowed ROE range in 2022 and expects earnings to be consistent with 2021. Warmer than normal weather adversely affected NSPI's sales volumes in 2021. NSPI expects sales volumes to be higher than 2021.

On September 24, 2022, Nova Scotia was struck by Hurricane Fiona, which made landfall as a post tropical storm equivalent to a Category 2 hurricane with sustained winds of over 100 kilometres per hour and peak gusts of approximately 180 kilometres per hour. This historic storm for Nova Scotia caused significant and widespread damage to NSPI's transmission and distribution system and at the height of the storm approximately 415,000 customers lost power. The total cost of restoration is expected to be approximately $115 million. As of September 30, 2022, NSPI incurred $48 million in storm restoration costs, of which $39 million was capitalized to Property, plant and equipment ("PP&E") and $9 million deferred to Other long-term assets for future amortization, subject to UARB approval. An estimated $67 million in additional storm restoration costs are expected to be incurred in Q4 2022 and NSPI anticipates that the allocation between PP&E and Other long-term assets will be similar to that of the costs incurred during Q3 2022.

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. The 2022 rates include approximately $162 million related to the recovery of Maritime Link costs (discussed below in the "ENL, NSPML" section).

On January 27, 2022, NSPI filed a General Rate Application ("GRA") with the UARB, which was then amended on February 18, 2022. The GRA proposes a rate stability plan for 2022 through 2024 which includes average rate increases of 2.8 per cent per year on August 1, 2022, January 1, 2023 and January 1, 2024 to recover non-fuel costs. On September 2, 2022, NSPI filed a fuel update to the GRA proposing that the cost of fuel increases be smoothed over 2023 and 2024 and the forecast Fuel Adjustment Mechanism ("FAM") balance at December 31, 2022 be recovered over three years (2023 through 2025), resulting in combined fuel rate increases of 1.6 per cent on January 1, 2023 and January 1, 2024 to recover fuel costs. The remaining recovery of the 2022 FAM balance is forecast to be collected in 2025 and would require an additional fuel rate increase of 1.3 per cent, subject to UARB approval in future rate applications. The effective timing of any approved increases would be determined by the UARB. The hearing for this matter concluded in September 2022 with closing submissions to be filed in Q4 2022. A decision by the UARB is expected in Q1 2023.

On November 9, 2022, the Nova Scotia provincial government enacted Bill 212, "Public Utilities Act (amended)". The legislation pre-empts the pending UARB GRA decision and limits non-fuel rate increases, excluding increases relating to demand-side management costs, to a total of 1.8 per cent between the effective date of the UARB's decision and the end of 2024. The legislation also:

- requires revenue generated from the non-fuel rate increase to be used only to improve the reliability of service to ratepayers;
- limits NSPI's return on equity to 9.25 per cent and equity ratio to 40 per cent; and
- limits the rate used to accrue interest on regulatory deferrals to the Bank of Canada policy interest rate plus 1.75 per cent, unless otherwise directed by the UARB.

Actions required to address the impact of this legislation are likely to include a material reduction in NSPI's planned capital investments and operating costs over the 2023 through 2024 period. As a result, planned expenditures for 2023 and 2024 will be deferred, resulting in higher customer costs in future periods. The legislation will have a direct and negative impact on the expected financial performance of NSPI such that it is not expected to earn within its currently allowed return on equity band in 2023 and 2024 at the currently approved equity ratio of 37.5 per cent. The Company has updated its principal risks disclosure to reflect this development. Refer to the "Risk Management and Financial Instruments" section and note 20 in the Q3 2022 unaudited condensed consolidated financial statements for this risk update.

Energy from renewable sources has increased with Nalcor Energy's ("Nalcor") NS Block delivery obligations from the Muskrat Falls hydroelectric project ("Muskrat Falls") commencing August 15, 2021. Nalcor is obligated to provide NSPI with approximately 900 GWh of energy annually over 35 years. In addition, for the first five 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. Nalcor's final commissioning of the LIL has experienced delays and Nalcor is working toward final commissioning of the LIL in Q4 2022. During these final stages of commissioning, there will be interruptions in supply, with any resultant delivery shortfalls being delivered at a date to be agreed to by the companies. NSPI has the option of purchasing additional market-priced energy from Nalcor through the Energy Access Agreement. The Energy Access Agreement enables NSPI to access a market-priced bid from Nalcor for up to 1.8 TWh of energy in any given year and, on average, 1.2 TWh of energy per year through August 31, 2041.

In 2022, NSPI expects to invest $545 million (2021 – $388 million), including AFUDC, primarily in capital projects to support system reliability, renew hydroelectric infrastructure, and add renewable capacity.

Environmental Legislation and Regulations

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 compliance will be recoverable under NSPI's regulatory framework. NSPI faces risks associated with achieving climate-related and environmental legislative requirements, including the risk of non-compliance, which could adversely affect NSPI's operations and financial performance. For further discussion on these risks and environmental legislation and regulations, refer to the "Enterprise Risk and Risk Management" and "Business Overview and Outlook – Canadian Electric Utilities" sections respectively of Emera's 2021 annual MD&A. Recent developments related to provincial and federal environmental laws and regulations are outlined below.

Nova Scotia Cap-and-Trade Program Regulations:
NSPI is a participant in the Nova Scotia Cap-and-Trade Program and is subject to the 2019 through 2022 compliance period. NSPI received granted emission allowances under the Cap-and-Trade Program and is permitted to purchase up to five per cent of the credits available at provincial auctions or reserve credits, which are anticipated to be priced at a premium, from the provincial government. Lower than forecasted Muskrat Falls energy received during the compliance period has resulted in the increased deployment of higher carbon-emitting generation sources. The Province of Nova Scotia has announced that it will provide $165 million of relief from the 2019 through 2022 compliance costs, which was equal to the total cost of compliance forecasted at the time of the September 2022 GRA fuel update. Discussions related to how this relief will be provided are ongoing.

Carbon Pricing Regulations:
On November 9, 2022, the Nova Scotia provincial government enacted Bill 208, “Environment Act (amended)”. The legislation provides the framework for Nova Scotia’s system to comply with the federal government’s 2023 through 2030 carbon pollution pricing regulations laid out in the Pan-Canadian Framework on Clean Growth and Climate Change. Nova Scotia’s proposed system utilizes an output-based pricing system that will implement performance standards for large industrial greenhouse gas emitters to achieve emission reduction goals. Subsequent regulations will be required to detail how the pricing system will operate. The Province of Nova Scotia’s proposed output-based pricing system is subject to the approval of the federal government. If an agreement is not reached between the federal and provincial governments on a Nova Scotia system that meets the federal compliance criteria, Nova Scotia will be subject to the federal carbon pollution pricing backstop which will start at $65 per tonne in 2023 and increase by $15 per tonne annually, reaching $170 per tonne by 2030. NSPI anticipates that any prudently incurred costs required to comply with carbon pricing programs will be recoverable under NSPI’s regulatory framework.

Nova Scotia Renewable Energy Regulations:
The alternative compliance plan, under the provincially legislated Renewable Energy Regulations, requires NSPI to achieve 40 per cent of electric sales generated from renewable sources over the 2020 through 2022 period. With delivery of the NS Block commencing later than anticipated, as well as further interruptions in supply due to delays in the LIL, NSPI is not forecasting the ability to achieve the requirements of the alternative compliance plan. The Renewable Energy Regulations require NSPI to have acted in a duly diligent manner. If NSPI is found not to have acted in a duly diligent manner, it could be subject to a maximum penalty of $10 million.

ENL

Absent the NSPML unrecoverable costs and potential holdback, equity earnings from NSPML and LIL are expected to be consistent in 2022, compared to 2021. Both NSPML and LIL investments are recorded as “Investments subject to significant influence” on Emera’s Condensed Consolidated Balance Sheets.

NSPML

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.

The Maritime Link assets entered into service on January 15, 2018, enabling the transmission of energy between Newfoundland and Nova Scotia, improved reliability and ancillary benefits, and supporting the efficiency and reliability of energy in both provinces. For further information on the NS Block, refer to the NSPI section above.

On August 3, 2022, NSPML submitted an application to the UARB requesting recovery of approximately $164 million in Maritime Link costs for 2023. A decision is expected in Q4 2022.

In February 2022, the UARB issued its decision and Board Order approving NSPML’s requested rate base of approximately $1.8 billion less approximately $9 million of costs ($7 million after-tax) that would not otherwise have been recoverable if incurred by NSPI. NSPML also received approval to collect $168 million (2021- $172 million) from NSPI for the recovery of Maritime Link costs in 2022. This is subject to a monthly holdback of up to $2 million from April to December 2022 contingent on receiving at least 90 per cent of NS Block deliveries, including Supplementary Energy deliveries, and the cost of replacement energy.

NSPML does not anticipate any significant capital investment in 2022 (2021 – $6 million).

LIL

ENL is a limited partner with Nalcor in LIL. Construction of the LIL is complete and Nalcor is working toward final commissioning in 2022.

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera's current equity investment is $725 million, comprised of $410 million in equity contribution and $315 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 the Lower Churchill projects 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.

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 an intrastate 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.

Gas Utilities and Infrastructure USD earnings are anticipated to be higher in 2022 than 2021, primarily due to customer growth and the reversal of accumulated depreciation at PGS, as discussed below.

PGS anticipates earning within its allowed ROE range in 2022 and expects rate base and USD earnings to be higher than in 2021. PGS expects favourable customer growth in 2022 and residential and commercial sales volumes in 2022 are expected to increase at a level slightly below customer growth. The PGS rate case settlement, which was approved in November 2020, also provides the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. Through September 2022, PGS reversed $14 million USD accumulated depreciation. The reversal of the remaining accumulated depreciation is expected to occur over the 2022 and 2023 periods.

In September 2022, Hurricane Ian impacted PGS's operations in Fort Myers and Sarasota. The estimated restoration costs are expected to be up to $3 million USD and will be charged against PGS's FPSC approved storm reserve, resulting in minimal impact to earnings.

NMGC anticipates earning below its authorized ROE in 2022 and expects rate base to be higher than 2021. NMGC expects customer growth rates to be consistent with historical trends.

On December 13, 2021, NMGC filed a rate case with the NMPRC for new rates to become effective January 2023. On May 20, 2022, NMGC filed an unopposed settlement agreement with the NMPRC for an increase of $19 million USD in annual base revenues. The proposed rates reflect the recovery of increased operating costs and capital investments in pipelines and related infrastructure. A hearing was held in June 2022 and a decision from the NMPRC is expected in Q4 2022.

In 2018, SeaCoast executed a 34-year agreement to provide long-term firm gas transportation service via a 21-mile, 30-inch pipeline lateral. The lease of the pipeline lateral commenced January 1, 2022.

In 2022, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $440 million USD (2021 - $407 million USD), including AFUDC. PGS will make investments to support customer growth and expand its system to ensure reliability. NMGC will continue to make investments to maintain the reliability of its system.

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, 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 31, 2022, Emera completed the sale of its 51.9 per cent interest in Dominica Electricity Services Ltd. ("Domlec") for proceeds which approximated carrying value. Domlec was included in the Other Electric segment in Q1 2022. The sale did not have a material impact on earnings.

Other Electric Utilities' USD earnings in 2022 are expected to increase over the prior year due to higher earnings due to higher base rates at GBPC and BLPC and the continued recovery in local economies from the impacts of COVID-19.

Effective November 1, 2022, GBPC's fuel pass through charge was increased due to an increase in global oil prices impacting the unhedged fuel cost. In 2023 the fuel pass through charge will be adjusted monthly in-line with actual fuel costs.

On January 14, 2022, the GBPA issued its decision on GBPC's rate application. The approved increase in annual revenues of $3.5 million USD commenced on April 1, 2022.

On October 4, 2021 BLPC submitted a general rate review application to the FTC. The application seeks a rate adjustment and the implementation of a cost reflective rate structure that will facilitate the changes expected in the newly reformed electricity market and the country's transition towards 100 per cent renewable energy generation. The application seeks recovery of capital investment in plant, equipment and related infrastructure and results in an increase in annual non-fuel revenue of approximately $23 million USD upon approval. The application includes a request for an allowed regulatory ROE of 12.50 per cent on an allowed equity capital structure of 65 per cent. On September 16, 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $3 million USD for the remainder of 2022. Interim rate relief is effective from September 16, 2022 until the implementation of final rates. The hearing concluded in October 2022 and BLPC expects a decision on final rates from the FTC in 2022.

In 2022, capital investment in the Other Electric Utilities segment is expected to be $60 million USD (2021 – $88 million USD), primarily in more efficient and cleaner sources of generation.

Other

The Other segment includes 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 the Other segment include Emera Energy and Emera Technologies LLC ("ETL"). Emera Energy consists of 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 633 MW pumped storage hydroelectric facility in northwestern Massachusetts. ETL is a wholly owned technology company focused on finding ways to deliver renewable and resilient energy to customers.

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 United States. 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 natural gas and electricity 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 income within its guidance range of $15 to $30 million USD ($45 to $70 million USD of margin).

The adjusted net loss from the Other segment is expected to be higher in 2022 due to higher Corporate OM&G which is primarily driven by the timing of long-term compensation and related hedges, realized FX gains on cash flow hedges in 2021, increased interest expense, and additional preferred dividends. This is expected to be partially offset by decreased taxes due to a higher net loss.

The Other segment does not anticipate any significant capital investments in 2022. (2021 - $1 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Condensed Consolidated Balance Sheets between December 31, 2021 and September 30, 2022 include:

millions of dollars		Increase (Decrease)	Explanation
Assets			
Cash and cash equivalents	**$**	**132**	Increased due to proceeds from short-term debt issuance at Emera and Tampa Electric, cash from operations, and issuance of common stock. These were partially offset by increased investment in PP&E at the regulated utilities and dividends on common stock
Inventory		**184**	Increased due to higher commodity prices at Emera Energy and NSPI and the effect of a weaker CAD on the translation of Emera's foreign affiliates
Derivative instruments (current and long-term)		**396**	Increased due to higher commodity prices at NSPI and reversal of 2021 contracts at Emera Energy, partially offset by settlements at NSPI
Regulatory assets (current and long-term)		**865**	Increased due to higher fuel cost recovery clauses at Tampa Electric, the effect of a weaker CAD on the translation of Emera's foreign affiliates, increased FAM deferrals at NSPI, increased deferred income tax regulatory assets at NSPI and Tampa Electric, and recognition of storm reserve asset at Tampa Electric due to restoration costs from Hurricane Ian in excess of the storm reserve liability. These were partially offset by recovery of gas costs from the NMGC 2021 winter event
Receivables and other assets (current and long-term)		**1,116**	Increased due to higher gas transportation assets and cash collateral at Emera Energy, the effect of a weaker CAD on the translation of Emera's foreign affiliates, and higher trade receivables at Tampa Electric
PP&E, net of accumulated depreciation and amortization		**2,202**	Increased due to the effect of a weaker CAD on the translation of Emera's foreign affiliates, and capital additions. These were partially offset by reclassification of Seacoast's pipeline lateral on commencement of the lease
Net investment in direct finance and sales type leases		**101**	Increased due to commencement of the pipeline lease at Seacoast
Goodwill		**462**	Increased due to the effect of a weaker CAD on the translation of Emera's foreign affiliates

millions of dollars	Increase (Decrease)	Explanation
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**$ 1,974**	Increased due to the effect of a weaker CAD on the translation of Emera's foreign affiliates, issuance of short-term debt at Emera and Tampa Electric, and net borrowings under the committed credit facility at NSPI
Accounts payable	**586**	Increased due to the effect of a weaker CAD on the translation of Emera's foreign affiliates, higher cash collateral position on derivative instruments at NSPI, increased commodity prices at Emera Energy and Tampa Electric, and timing of payments at Tampa Electric and NSPI
Deferred income tax liabilities, net of deferred income tax assets	**120**	Increased due to tax deductions in excess of accounting depreciation related to PP&E and increase in net regulatory assets, partially offset by net increase in tax loss carryforwards
Derivative instruments (current and long-term)	**1,119**	Increased due to new contracts in 2022 and changes in existing positions, partially offset by reversal of 2021 contracts at Emera Energy
Regulatory liabilities (current and long-term)	**317**	Increased due to deferrals related to derivative instruments at NSPI and the effect of a weaker CAD on the translation of Emera's foreign affiliates, partially offset by decreased storm reserve at Tampa Electric due to restoration costs incurred from Hurricane Ian
Other liabilities (current and long-term)	**392**	Increased due to accrued emissions compliance charges at NSPI, higher investment tax credits related to solar projects at Tampa Electric, and the effect of a weaker CAD on the translation of Emera's foreign affiliates
Common stock	**433**	Increased due to Emera's ATM equity program and shares issued under the dividend reinvestment program
Accumulated other comprehensive income	**638**	Increased due to the effect of a weaker CAD on the translation of Emera's foreign affiliates
Retained earnings	**(63)**	Decreased due to dividends paid in excess of net income

OTHER DEVELOPMENTS

USGAAP Reporting Extension

Emera was granted exemptive relief by Canadian securities regulators on September 13, 2022, and under the Companies Act (Nova Scotia) on October 12, 2022, each allowing Emera to continue to report its financial results in accordance with USGAAP (collectively the “Exemptive Relief”). The Exemptive Relief will terminate on the earliest of: (i) January 1, 2027; (ii) if the Company ceases to have rate-regulated activities, the first day of the Company’s financial year that commences after the Company ceases to have rate-regulated activities; and (iii) the first day of the Company’s financial year that commences on or following the later of: (a) the effective date prescribed by the International Accounting Standards Board (“IASB”) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities (“Mandatory Rate-regulated Standard”); and (b) two years after the IASB publishes the final version of a Mandatory Rate-regulated Standard. The Exemptive Relief replaces similar relief that had been granted to Emera in 2018 and would have expired by no later than January 1, 2024.

Increase in Common Dividends

On September 22, 2022, the Emera Board of Directors approved an increase in the annual common share dividend rate to $2.76 from $2.65. The first payment will be effective November 15, 2022. Emera also extended its dividend growth rate target of four to five per cent through 2025.

Appointments

Effective July 1, 2022, Michael Barrett was appointed Executive Vice President and General Counsel for Emera. Mr. Barrett was most recently the General Counsel for Emera.

Effective June 30, 2022, Bruce Marchand was appointed Chief Risk and Sustainability Officer for Emera. Mr. Marchand was most recently the Chief Legal and Compliance Officer for Emera.

FINANCIAL HIGHLIGHTS

Florida Electric Utility

All amounts are reported in USD, unless otherwise stated.

For the millions of USD (except as indicated)	Three months ended September 30 **2022**	 2021	Nine months ended September 30 **2022**	 2021
Operating revenues – regulated electric	**$ 753**	$ 634	**$ 1,926**	$ 1,613
Regulated fuel for generation and purchased power	**$ 270**	$ 217	**$ 631**	$ 501
Contribution to consolidated net income	**$ 153**	$ 135	**$ 367**	$ 302
Contribution to consolidated net income (CAD)	**$ 199**	$ 169	**$ 472**	$ 377
Electric sales volumes (Gigawatt hours ("GWh"))	**6,259**	6,003	**16,002**	15,332
Electric production volumes (GWh)	**6,341**	6,256	**16,675**	16,211
Average fuel cost per megawatt hour ("MWh")	**$ 43**	$ 35	**$ 38**	$ 31

The impact of the change in the FX rate increased CAD earnings for the three and nine months ended September 30, 2022 by $7 million and $13 million, respectively.

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

For the millions of USD	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2021	**$ 135**	**$ 302**
Increased operating revenues due to higher fuel recovery clause revenue as a result of increased fuel costs, new rates effective January 2022, and customer growth. Year-over-year also increased due to favourable weather	119	313
Increased fuel for generation and purchased power due to higher natural gas prices	(53)	(130)
Increased OM&G expenses due to timing of deferred clause recoveries, higher benefit costs, and higher transmission and distribution costs. Year-over-year also due to higher insurance costs	(18)	(46)
Increased depreciation and amortization due to additions to facilities and the in-service of generation projects	(4)	(10)
Increased interest expense due to higher interest rates and higher borrowings to support Tampa Electric's ongoing capital investment	(11)	(16)
Decreased AFUDC earnings due to the timing of power plant modernization and solar projects	(3)	(6)
Increased income tax expense primarily due to increased income before provision for income taxes	(11)	(36)
Other	(1)	(4)
Contribution to consolidated net income – 2022	**$ 153**	**$ 367**

Canadian Electric Utilities

For the millions of dollars (except as indicated)		Three months ended September 30 **2022**		2021		Nine months ended September 30 **2022**		2021
Operating revenues – regulated electric	**$**	**370**	$	328	**$**	**1,254**	$	1,112
Regulated fuel for generation and purchased power (1)	**$**	**239**	$	169	**$**	**777**	$	554
Contribution to consolidated adjusted net income	**$**	**39**	$	42	**$**	**176**	$	174
NSPML unrecoverable costs	**$**	**-**	$	-	**$**	**(7)**	$	-
Contribution to consolidated net income	**$**	**39**	$	42	**$**	**169**	$	174
Electric sales volumes (GWh)		**2,262**		2,263		**7,833**		7,570
Electric production volumes (GWh)		**2,397**		2,402		**8,320**		8,062
Average fuel costs per MWh	**$**	**100**	$	70	**$**	**93**	$	69

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

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

For the millions of dollars		Three months ended September 30 **2022**		2021		Nine months ended September 30 **2022**		2021
NSPI	**$**	**20**	$	18	**$**	**108**	$	98
Equity investment in NSPML (1)		**5**		12		**28**		39
Equity investment in LIL		**14**		12		**40**		37
Contribution to consolidated adjusted net income	**$**	**39**	$	42	**$**	**176**	$	174

(1) Excludes $7 million in NSPML unrecoverable costs, after-tax, for the nine months ended September 30, 2022 (2021 – nil).

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

For the millions of dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2021	**$**	**42**	**$**	**174**
Increased operating revenues due to increased electric revenues related to recovery of fuel costs from an industrial customer, increased residential and commercial class sales volumes, and increased sales volumes due to weather		42		142
Increased regulated fuel for generation and purchased power due to increased Nova Scotia Cap-and-Trade program provision, increased commodity prices and higher Maritime Link assessment costs, partially offset by a favourable change in generation mix. Year-to-date also due to increased sales volumes		(70)		(223)
Increased FAM and fixed cost deferrals due to current period under-recovery of fuel costs		29		104
Increased OM&G year-over-year, primarily due to increased information technology, storm restoration, and power generation expenses		(2)		(27)
Decreased income from equity investment in NSPML primarily due to the Maritime Link holdback		(7)		(11)
Decreased income tax expense primarily due to increased tax deductions in excess of accounting depreciation and amortization related to PP&E and deferrals, and decreased non-deductible pension expense		6		11
NSPML unrecoverable costs		-		(7)
Other		(1)		6
Contribution to consolidated net income – 2022	**$**	**39**	**$**	**169**

The provision for the Nova Scotia Cap-and-Trade program was $40 million for the three months ended September 30, 2022 (2021 – $nil) and $152 million for the nine months ended September 30, 2022 (2021 – $3 million). For further information on this non-cash accrual, the estimated costs and the FAM regulatory balance, refer to note 6 in the Q3 2022 unaudited condensed consolidated interim financial statements.

Gas Utilities and Infrastructure

All amounts are reported in USD, unless otherwise stated.

For the millions of USD (except as indicated)	Three months ended September 30 **2022**	 2021	Nine months ended September 30 **2022**	 2021
Operating revenues – regulated gas (1)	**$ 260**	$ 189	**$ 924**	$ 699
Operating revenues – non-regulated	**4**	3	**10**	10
Total operating revenue	**$ 264**	$ 192	**$ 934**	$ 709
Regulated cost of natural gas	**$ 115**	$ 57	**$ 433**	$ 236
Contribution to consolidated net income	**$ 25**	$ 22	**$ 117**	$ 113
Contribution to consolidated net income (CAD)	**$ 33**	$ 29	**$ 149**	$ 143
Gas sales volumes (Therms)	**636**	609	**2,123**	2,089

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2021 - $11 million) for the three months ended September 30, 2022 and $34 million (2021 - $34 million) for the nine months ended September 30, 2022.

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

For the millions of USD	Three months ended September 30 **2022**	 2021	Nine months ended September 30 **2022**	 2021
PGS	**$ 16**	$ 14	**$ 65**	$ 60
NMGC	**(4)**	(4)	**13**	18
Other	**13**	12	**39**	35
Contribution to consolidated net income	**$ 25**	$ 22	**$ 117**	$ 113

The impact of the change in the FX rate increased CAD earnings for the three and nine months ended September 30, 2022 by $1 million and $2 million, respectively.

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

For the millions of USD	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2021	**$ 22**	**$ 113**
Increased gas revenues due to higher purchased gas adjustment clause revenues at PGS and NMGC as a result of higher gas prices, and higher off-system sales at PGS. Year-over-year also increased due to customer growth at PGS	71	225
Increased cost of natural gas sold due to higher gas prices at PGS and NMGC, and higher off-system sales at PGS	(58)	(197)
Increased OM&G primarily due to higher labour and benefits costs at PGS and NMGC	(9)	(19)
Decreased depreciation and amortization expense due to reversal of accumulated depreciation as a result of the rate case settlement at PGS, partially offset by increases due to asset growth at PGS and NMGC	2	8
Increased interest expense due to higher interest rates	(4)	(6)
Other	1	(7)
Contribution to consolidated net income – 2022	**$ 25**	**$ 117**

Other Electric Utilities

All amounts are reported in USD, unless otherwise stated.

For the millions of USD (except as indicated)	Three months ended September 30 2022	2021	Nine months ended September 30 2022	2021
Operating revenues – regulated electric	**$ 104**	$ 96	**$ 300**	$ 257
Regulated fuel for generation and purchased power	**$ 58**	$ 46	**$ 169**	$ 123
Contribution to consolidated adjusted net income	**$ 9**	$ 6	**$ 16**	$ 12
Contribution to consolidated adjusted net income (CAD)	**$ 12**	$ 8	**$ 21**	$ 15
Equity securities MTM loss	**$ (1)**	$ -	**$ (5)**	$ (1)
Contribution to consolidated net income	**$ 8**	$ 6	**$ 11**	$ 11
Contribution to consolidated net income (CAD)	**$ 10**	$ 8	**$ 14**	$ 14
Electric sales volumes (GWh)	**329**	337	**938**	932
Electric production volumes (GWh)	**352**	365	**1,004**	1,002

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

For the millions of USD	Three months ended September 30 2022	2021	Nine months ended September 30 2022	2021
GBPC	**$ 6**	$ 3	**$ 9**	$ 8
BLPC	**3**	3	**6**	5
Other	**-**	-	**1**	(1)
Contribution to consolidated adjusted net income	**$ 9**	$ 6	**$ 16**	$ 12

The impact of the change in the FX rate on CAD earnings for the three months and nine months ended September 30, 2022 was minimal.

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

For the millions of USD	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2021	**$ 6**	**$ 11**
Increased operating revenues – regulated electric due to higher fuel revenue at BLPC as a result of higher fuel prices, partially offset by the sale of Domlec in Q1 2022	8	43
Increased regulated fuel for generation and purchased power as a result of higher fuel prices at BLPC	(12)	(46)
Decreased OM&G due to the sale of Domlec in Q1 2022 and lower generation costs at GBPC, partially offset by the recognition of Hurricane Dorian insurance proceeds at GBPC in 2021	6	6
Other	-	(3)
Contribution to consolidated net income – 2022	**$ 8**	**$ 11**

Other

For the millions of dollars	Three months ended September 30 2022	2021	Nine months ended September 30 2022	2021
Marketing and trading margin (1) (2)	**$ 24**	$ (4)	**$ 71**	$ 63
Other non-regulated operating revenue	**3**	8	**13**	25
Total operating revenues – non-regulated	**$ 27**	$ 4	**$ 84**	$ 88
Contribution to consolidated adjusted net income (loss)	**$ (80)**	$ (73)	**$ (217)**	$ (154)
MTM loss, after-tax (3)	**(34)**	(245)	**(125)**	(368)
Contribution to consolidated net income (loss)	**$ (114)**	$ (318)	**$ (342)**	$ (522)

(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 MTM loss, pre-tax of $32 million in Q3 2022 (2021 - $334 million loss) and a loss of $149 million year-to-date (2021 – $501 million loss).
(3) Net of income tax recovery of $14 million for the three months ended September 30, 2022 (2021 - $100 million recovery) and $51 million recovery for the nine months ended September 30, 2022 (2021 - $149 million recovery).

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

For the millions of dollars	Three months ended September 30 2022	2021	Nine months ended September 30 2022	2021
Emera Energy	**$ 8**	$ (5)	**$ 29**	$ 37
Corporate – see breakdown of adjusted contribution below	**(84)**	(59)	**(230)**	(174)
Emera Technologies	**(3)**	(7)	**(13)**	(13)
Other	**(1)**	(2)	**(3)**	(4)
Contribution to consolidated adjusted net income (loss)	**$ (80)**	$ (73)	**$ (217)**	$ (154)

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

For the millions of dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income (loss) – 2021	**$ (318)**	**$ (522)**
Increased marketing and trading margin due to higher natural gas prices and volatility, which created profitable opportunities for Emera Energy. Year-over-year increase was offset by the positive margin impact of Winter Storm Uri in Q1 2021	28	8
Increased OM&G, pre-tax, primarily due to the timing of long-term compensation and related hedges	(17)	(36)
Increased interest expense, pre-tax, due to increased interest rates and increased total debt	(10)	(10)
Increased FX loss, pre-tax, primarily due to realized gains in 2021 on FX hedges entered into to hedge USD denominated operating unit earnings exposure	(6)	(19)
Increased income tax recovery primarily due to increased losses before provision for income taxes	3	20
Increased preferred stock dividends due to issuance of preferred shares in 2021	(2)	(11)
Decreased MTM loss, after tax, quarter-over-quarter, primarily due to changes in existing positions, partially offset by higher amortization of gas transportation assets in 2022 and larger reversal of MTM losses in 2021 at Emera Energy. Decreased MTM loss, after tax, year-over-year primarily due to larger reversal of MTM losses in 2022 and changes in existing positions, partially offset by higher amortization of gas transportation assets in 2022 at Emera Energy	211	243
Other	(3)	(15)
Contribution to consolidated net income (loss) – 2022	**$ (114)**	**$ (342)**

Corporate

Corporate's adjusted loss is summarized in the following table:

For the millions of dollars	Three months ended September 30 **2022**	 2021	Nine months ended September 30 **2022**	 2021
Operating expenses (1)	**$ 27**	$ 10	**$ 63**	$ 27
Interest expense	**75**	65	**208**	199
Income tax recovery	**(29)**	(18)	**(74)**	(57)
Preferred dividends	**16**	14	**47**	36
Other (2)	**(5)**	(12)	**(14)**	(31)
Corporate adjusted net loss	**$ (84)**	$ (59)	**$ (230)**	$ (174)

(1) Operating expenses include OM&G and depreciation. In 2021, OM&G and depreciation were offset by changes in long-term compensation. The value of long-term compensation and related hedges are impacted by the changes in Emera's period end share price.
(2) 2021 includes $4 million quarter-to-date and $13 million year-to-date of realized gains on FX cash flow hedges to hedge FX earnings exposure. A loss of $1 million was recognized year-to-date in 2022.

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 changes to global macro-economic conditions, downturns in markets served by Emera, impact of fuel commodity price changes on collateral requirements and timely recoveries of fuel costs from customers, 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.

For information on COVID-19 and its potential future impacts on Emera's liquidity and capital resources, refer to the "Business Overview and Outlook" and "Liquidity and Capital Resources" sections in Emera's 2021 annual MD&A.

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 an $8 – 9 billion capital investment plan over the 2023-to-2025 period (including a $240 million equity investment in the LIL in 2023). This plan includes significant rate base investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. Capital investments at the regulated utilities are subject to regulatory approval.

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 are expected to be funded through the issuance of preferred equity and the issuance of common equity through Emera's dividend reinvestment plan and ATM program.

Emera has credit facilities with varying maturities that cumulatively provide $4.6 billion of credit, with approximately $1.4 billion undrawn and available at September 30, 2022. The Company was holding a cash balance of $549 million at September 30, 2022. For further discussion, refer to the "Debt Management" section below. For additional information regarding the credit facilities, refer to notes 18 and 19 in the unaudited condensed consolidated interim financial statements.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the nine months ended September 30, 2022 and 2021 include:

millions of dollars		2022		2021		Change
Cash, cash equivalents, and restricted cash, beginning of period	**$**	**417**	$	254	$	163
Provided by (used in):						
Operating cash flow before change in working capital		**806**		1,035		(229)
Change in working capital		**149**		71		78
Operating activities	**$**	**955**	$	1,106	$	(151)
Investing activities		**(1,685)**		(1,576)		(109)
Financing activities		**844**		693		151
Effect of exchange rate changes on cash, cash equivalents, and restricted cash		**18**		(1)		19
Cash, cash equivalents, and restricted cash, end of period	**$**	**549**	$	476	$	73

Cash Flow from Operating Activities

Net cash provided by operating activities decreased $151 million to $955 million for the nine months ended September 30, 2022, compared to $1,106 million for the same period in 2021.

Cash from operations before changes in working capital decreased $229 million. This decrease was due to under-recovery of clause-related costs primarily due to higher natural gas prices at Tampa Electric, unfavourable changes in Tampa Electric’s storm reserve balance as a result of Hurricane Ian, and increased fuel for generation and purchased power at NSPI. This was partially offset by the 2021 deferral of gas costs at NMGC resulting from the extreme cold weather event, and increased revenues at Tampa Electric and NSPI.

Changes in working capital increased operating cash flows by $78 million year-over-year. This increase was due to favourable changes in accounts payable at Tampa Electric and NSPI, and favourable changes in cash collateral positions at Emera Energy. This was partially offset by unfavourable changes in accounts receivable at Tampa Electric, NSPI and GBPC, unfavourable changes in cash collateral positions on derivative instruments at NSPI, and the required prepayment of income taxes and related interest at NSPI.

Cash Flow from Investing Activities

Net cash used in investing activities increased $109 million to $1,685 million for the nine months ended September 30, 2022, compared to $1,576 million for the same period in 2021. The increase was due to higher capital investment in 2022.

Capital investments, including AFUDC, for the nine months ended September 30, 2022, were $1,742 million compared to $1,640 million for the same period in 2021. Details of the 2022 capital investment by segment are shown below:

- $980 million – Florida Electric Utility (2021 – $927 million);
- $311 million – Canadian Electric Utilities (2021 – $248 million);
- $405 million – Gas Utilities and Infrastructure (2021 – $378 million);
- $43 million – Other Electric Utilities (2021 – $85 million); and
- $3 million – Other (2021 – $2 million).

Cash Flow from Financing Activities

Net cash provided by financing activities increased $151 million to $844 million for the nine months ended September 30, 2022, compared to $693 million for the same period in 2021. This increase was due to the retirement of long-term debt at NMGC in 2021, repayment of short-term debt at Tampa Electric and PGS in 2021, and increased proceeds from short-term debt at Emera and Tampa Electric in 2022. This was partially offset by lower issuances of long-term debt at NMGC, PGS and Tampa Electric, and the issuance of preferred shares in 2021.

Contractual Obligations

As at September 30, 2022, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2022	2023	2024	2025	2026	Thereafter	Total
Long-term debt principal	$ 9	596	1,606	511	3,185	10,079	$ 15,986
Interest payment obligations (1)	269	695	674	625	532	7,497	10,292
Transportation (2)	183	616	475	396	364	2,917	4,951
Purchased power (3)	77	268	247	242	232	2,394	3,460
Fuel, gas supply and storage	487	991	305	170	37	-	1,990
Capital projects	399	253	88	4	1	-	745
Asset retirement obligations	7	7	2	2	1	415	434
Pension and post-retirement obligations (4)	8	40	35	34	34	173	324
Equity investment commitments (5)	-	240	-	-	-	-	240
Other	46	86	81	60	44	223	540
	$ 1,485	$ 3,792	$ 3,513	$ 2,044	$ 4,430	$ 23,698	$ 38,962

(1) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at September 30, 2022, including any expected required payment under associated swap agreements.
(2) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $147 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(3) Annual requirement to purchase electricity production from Independent Power Producers or other utilities over varying contract lengths.
(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) Emera has a commitment to make equity contributions to the LIL upon its commissioning.

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. In February 2022, the UARB issued its decision and Board Order approving NSPML’s requested rate base of approximately $1.8 billion and the approval to collect $168 million from NSPI for the recovery of Maritime Link costs in 2022. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Once LIL has been commissioned, 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, if requested, to enable it to transmit energy which is not otherwise used in Newfoundland and Labrador or Nova Scotia. Nalcor has the right to transmit this energy from Nova Scotia to New England energy markets effective August 15, 2021, the date the NS Block delivery obligation commenced, and continuing for 50 years. As transmission rights are contracted, the obligations are included within “Other” in the above table.

Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2021 annual MD&A, with material updates as noted below:

The Company has standby letters of credit and surety bonds in the amount of $125 million USD (December 31, 2021 - $148 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. has issued a guarantee of $66 million USD relating to outstanding notes of ECI. This guarantee will automatically terminate on the date upon which the obligations have been repaid in full.

TECO Energy issued a guarantee in connection with SeaCoast's performance obligations under a firm service agreement, which expires on December 31, 2055, subject to two extension terms at the option of the counterparty with a final expiration date of December 31, 2071. The guarantee is for a maximum potential amount of $13 million USD if SeaCoast fails to pay or perform under the firm service agreement. In the event that TECO Energy's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would need to provide either a substitute guarantee from an affiliate with an investment grade credit rating or a letter of credit or cash deposit of $13 million USD.

Debt Management

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

millions of dollars	Maturity	Credit Facilities	Utilized	Undrawn and Available
Emera – Unsecured committed revolving credit facility	June 2026	$ 900	$ 583	$ 317
TEC (in USD) – Unsecured committed revolving credit facility (1)	December 2026	800	351	449
NSPI – Unsecured committed revolving credit facility	December 2026	600	120	480
TEC (in USD) – Unsecured non-revolving facility (2)	December 2022	500	500	-
Emera – Unsecured non-revolving facility	December 2022	400	400	-
TECO Finance (in USD) – Unsecured committed revolving credit facility	December 2026	400	348	52
NSPI – Unsecured non-revolving facility	July 2024	400	400	-
Emera – Unsecured non-revolving facility	August 2023	400	400	-
NMGC (in USD) – Unsecured revolving credit facility	December 2026	125	39	86
NMGC (in USD) – Unsecured non-revolving facility	March 2024	80	80	-
Other (in USD) – Unsecured committed revolving credit facilities	Various	21	11	10

(1) This facility is available for use by Tampa Electric and PGS. At September 30, 2022, $295 million USD was used by Tampa Electric and $56 million USD was used by PGS.
(2) This facility is available for use by Tampa Electric and PGS. At September 30, 2022, $400 million USD was used by Tampa Electric and $100 million USD was used by PGS.

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 September 30, 2022.

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

Florida Electric Utilities

On September 15, 2022, TEC repaid a $250 million USD note upon maturity. The note was repaid using existing credit facilities.

On July 12, 2022, TEC completed an issuance of $600 million USD senior notes. The issuance included $300 million USD senior notes that bear an interest rate of 3.875 per cent with a maturity date of July 12, 2024, and $300 million USD senior notes that bear an interest rate of 5 per cent with a maturity date of July 15, 2052. Proceeds from the issuance were used to repay TEC's $470 million USD commercial paper, due in 2022, and for general corporate purposes.

Canadian Electric Utilities

On July 15, 2022, NSPI entered into a $400 million non-revolving term facility which matures on July 15, 2024. The credit agreement contains customary representation and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. Proceeds from this issuance were used for general corporate purposes.

Gas Utilities and Infrastructure

On September 23, 2022, NMGC amended its $80 million USD, unsecured, non-revolving credit facility to extend the maturity from September 23, 2022, to March 22, 2024. There were no other significant changes in commercial terms from the prior agreement.

On June 30, 2022, Brunswick Pipeline amended its credit agreement to extend the maturity from June 30, 2025 to June 30, 2026. There were no other changes in commercial terms from the prior agreement.

Other Electric Utilities

On March 25, 2022, ECI amended its amortizing floating rate notes to extend the maturity from March 25, 2022 to March 25, 2027. There were no other changes in commercial terms from the prior agreement.

Other

On August 2, 2022, Emera entered into a $400 million non-revolving term facility which matures on August 2, 2023. The credit agreement contains customary representation and warranties, events of default and financial and other covenants and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. Proceeds from this issuance were used for general corporate purposes.

Credit Ratings

On November 2, 2022, Moody's Investor Services ("Moody's") affirmed its Baa3 issuer rating for Emera Inc. Moody's also affirmed ratings on TECO Finance and TEC, affirming the TECO Finance Baa1 issuer rating and A3 issuer rating for TEC. Emera and subsidiaries' outlook was changed to negative from stable.

On October 24, 2022, S&P Global Ratings ("S&P") affirmed its BBB issuer rating for Emera Inc. S&P also affirmed ratings on NSPI, TECO Energy, and TEC affirming the BBB+ issuer credit ratings for NSPI and TEC. Emera and subsidiaries' outlook was changed to negative from stable.

On June 2, 2022, Moody's affirmed its Baa1 issuer rating for TECO Finance. Moody's also affirmed TEC's A3 issuer rating and changed the outlook to stable from positive.

Outstanding Stock Data

Common Stock

Issued and outstanding:	millions of shares		millions of dollars
Balance, December 31, 2021	261.07	$	7,242
Issuance of common stock under ATM program (1)	3.79		233
Issued under the Dividend Reinvestment Program, net of discounts	2.86		171
Senior management stock options exercised and Employee Share Purchase Plan	0.51		29
Balance, September 30, 2022	**268.23**	**$**	**7,675**

(1) In Q3 2022, 1,715,056 common shares were issued under Emera's ATM program at an average price of $61.87 per share for gross proceeds of $106 million ($105 million net of after-tax issuance costs). For the nine months ended September 30, 2022, 3,793,924 common shares were issued under Emera's ATM program at an average price of $61.85 per share for gross proceeds of $235 million ($233 million net of after-tax issuance costs). As at September 30, 2022, an aggregate gross sales limit of $222 million remained available for issuance under the ATM program.

As at November 8, 2022, the amount of issued and outstanding common shares was 268.3 million.

If all outstanding stock options were converted as at November 8, 2022, an additional 2.9 million common shares would be issued and outstanding.

Preferred Stock

As at November 8, 2022, Emera had the following preferred shares issued and outstanding: Series A – 4.9 million; Series B – 1.1 million; Series C – 10.0 million; Series E – 5.0 million; Series F – 8.0 million; Series H – 12.0 million; Series J – 8.0 million, and Series L – 9.0 million. Emera's preferred shares do not have voting rights unless the Company fails to pay, in aggregate, eight quarterly dividends.

TRANSACTIONS WITH RELATED PARTIES

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

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

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Condensed Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $41 million for the three months ended September 30, 2022 (2021 - $27 million) and $118 million for the nine months ended September 30, 2022 (2021 - $91 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 Condensed Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $1 million for the three months ended September 30, 2022 (2021 - $4 million) and $7 million for the nine months ended September 30, 2022 (2021 - $14 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at September 30, 2022 and at December 31, 2021.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

There have been no material changes in Emera's risk management profile and practices from those disclosed in the Company's 2021 annual MD&A, except for the following additional disclosure under "Regulatory and Political Risk":

On November 9, 2022, the Nova Scotia provincial government enacted Bill 212, "Public Utilities Act (amended)". This government intervention in the regulatory process has resulted in an increase in political risk and a reduction in the stability and predictability of NSPI's regulatory environment. This legislation sets an unfavourable precedent and significantly increases the risk associated with NSPI's current and future ability to recover prudently incurred costs including capital investments and regulatory assets.

Derivatives Assets and Liabilities Recognized on the Balance Sheet

As at millions of dollars	**September 30 2022**	December 31 2021
Regulatory Deferral:		
Derivative instrument assets (1)	**$ 447**	$ 237
Derivative instrument liabilities (2)	**(32)**	(20)
Regulatory assets (1)	**61**	23
Regulatory liabilities (2)	**(448)**	(241)
Net asset (liability)	**$ 28**	$ (1)
HFT Derivatives:		
Derivative instrument assets (1)	**$ 245**	$ 53
Derivatives instruments liabilities (2)	**(1,724)**	(662)
Net liability	**$ (1,479)**	$ (609)
Other Derivatives:		
Derivative instrument assets (1)	**$ 5**	$ 11
Derivatives instruments liabilities (2)	**(45)**	-
Net asset (liability)	**$ (40)**	$ 11

(1) Current and other assets.
(2) Current and long-term liabilities.

Realized and Unrealized Gains (Losses) Recognized in Net Income

For the millions of dollars		Three months ended September 30 **2022**		2021		Nine months ended September 30 **2022**		2021
Regulatory Deferral:								
Regulated fuel for generation and purchased power (1)	**$**	**51**	$	13	**$**	**142**	$	9
HFT Derivatives:								
Non-regulated operating revenues	**$**	**(567)**	$	(235)	**$**	**(635)**	$	(226)
Non-regulated fuel for generation and purchased power		**-**		-		**-**		1
Net losses	**$**	**(567)**	$	**(235)**	**$**	**(635)**	$	**(225)**
Other Derivatives:								
OM&G	**$**	**(12)**	$	3	**$**	**(21)**	$	9
Other income, net		**(32)**		(1)		**(31)**		2
Net gains (losses)	**$**	**(44)**	$	**2**	**$**	**(52)**	$	**11**
Total net losses	**$**	**(560)**	$	**(220)**	**$**	**(545)**	$	**(205)**

(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.

As of September 30, 2022, the unrealized gain in Accumulated other comprehensive income was $16 million, net of tax (2021 - $18 million, net of tax). For the three and nine months ended September 30, 2022, unrealized gains of $1 million (2021 - $1 million) and $2 million (2021 - $1 million), respectively, have been reclassified into interest expense. As of September 30, 2022, there were no outstanding cash flow hedges.

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. 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 of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design of the Company's DC&P and ICFR as at September 30, 2022, to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

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

There were no changes in the Company's ICFR during the quarter ended September 30, 2022 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

The preparation of unaudited condensed consolidated interim financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, 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 in income in the year they arise. There were no material changes in the nature of the Company's critical accounting estimates from those disclosed in Emera's 2021 annual MD&A.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Future Accounting Pronouncements

The Company considers the applicability and impact of all Accounting Standard Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"). ASUs issued by FASB, but which are not yet effective, were assessed and determined to be either not applicable to the Company or to have an insignificant impact on the unaudited condensed consolidated interim financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q3 2022**	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020
Operating revenues	**$ 1,835**	$ 1,380	$ 2,015	$ 1,868	$ 1,148	$ 1,137	$ 1,612	$ 1,537
Net income (loss) attributable to common shareholders	**$ 167**	$ (67)	$ 362	$ 324	$ (70)	$ (17)	$ 273	$ 273
Adjusted net income	**$ 203**	$ 156	$ 242	$ 168	$ 175	$ 137	$ 243	$ 188
Earnings (loss) per common share – basic	**$ 0.63**	$ (0.25)	$ 1.38	$ 1.24	$ (0.27)	$ (0.07)	$ 1.08	$ 1.09
Earnings (loss) per common share – diluted	**$ 0.63**	$ (0.25)	$ 1.38	$ 1.20	$ (0.27)	$ (0.07)	$ 1.08	$ 1.08
Adjusted earnings per common share – basic	**$ 0.76**	$ 0.59	$ 0.92	$ 0.64	$ 0.68	$ 0.54	$ 0.96	$ 0.75

Quarterly operating revenues and adjusted net income 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.