Management’s Discussion & Analysis

As at February 23, 2023

Management’s Discussion & Analysis (“MD&A”) provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments during the fourth quarter of 2022 relative to the same quarter in 2021; for the full year of 2022 relative to 2021 and selected financial information for 2020; and its financial position as at December 31, 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 annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2022. Emera follows United States Generally Accepted Accounting Principles (“USGAAP” or “GAAP”).

The accounting policies used by Emera’s rate-regulated entities may differ from those used by Emera’s non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. At December 31, 2022, Emera’s rate-regulated subsidiaries and investments include:

Emera Rate-Regulated Subsidiary or Equity Investment	**Accounting Policies Approved/Examined By**
Subsidiary	
Tampa Electric – Electric Division of Tampa Electric Company (“TEC”) (1)	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 (1)	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”)

(1) Effective January 1, 2023, Peoples Gas System ceased to be a division of TEC and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System, Inc., a wholly owned direct subsidiary of TECO Gas Operations, Inc.

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 United States dollar (“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.

TABLE OF CONTENTS

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 and political 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; inflation 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 ("IT") 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.

The majority of Emera's investment in rate-regulated businesses are located in Florida with other investments in Nova Scotia, New Mexico and the Caribbean. 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), mainly focused in Florida. 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 ("DRIP") and at-the-market program ("ATM program"). Maintaining investment-grade credit ratings is a priority of the Company.

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 USD relative to the 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 will play a role 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, 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 subject to supportive government and regulatory decisions, Emera is working 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.

Achieving the above climate goals on these timelines is subject to the Company's regulatory obligations and other external factors beyond Emera's control.

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 (Loss) Per Common Share ("EPS") – 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, impairment charges, the impact of the NSPML unrecoverable costs, and the 2020 gain on sale of Emera Maine.

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 therefore 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 hedges entered into to hedge USD denominated operating unit 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 Q4 2022, the Company recognized a $73 million non-cash goodwill impairment charge related to GBPC due to a decline in the fair value of the reporting unit. The fair value decline was driven by the effects of macro-economic factors on the discount rate calculation, including the risk-free rate assumption. Management believes excluding from net income the effect of this charge better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the Company. For further details on this GBPC impairment charge, refer to "Significant Items Impacting Earnings", 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 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.

In 2020, the Company recognized a gain on the sale of Emera Maine and certain non-cash impairment charges. Management believes excluding these from net income better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the business.

Adjusted EPS – basic and dividend payout ratio of adjusted net income are non-GAAP ratios which are calculated using adjusted net income, as described above. For further details on dividend payout ratio of adjusted net income, see the "Dividend Payout Ratio" section.
Emera calculates adjusted net income 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.

The following reconciles net income attributable to common shareholders to adjusted net income:

For the millions of dollars (except per share amounts)	Three months ended December 31 2022	2021	Year ended December 31 2022	2021	2020
Net income attributable to common shareholders	**$ 483**	$ 324	**$ 945**	$ 510	$ 938
MTM gain (loss), after-tax (1)	**307**	156	**175**	(213)	(10)
Impairment charges, after-tax (2)	**(73)**	-	**(73)**	-	(26)
NSPML unrecoverable costs (3)	**-**	-	**(7)**	-	-
Gain on sale, after tax and transaction costs (4)	**-**	-	**-**	-	309
Adjusted net income attributable to common shareholders	**$ 249**	$ 168	**$ 850**	$ 723	$ 665
EPS – basic	**$ 1.80**	$ 1.24	**$ 3.56**	$ 1.98	$ 3.78
Adjusted EPS – basic	**$ 0.93**	$ 0.64	**$ 3.20**	$ 2.81	$ 2.68

(1) Net of income tax expense of $124 million for the three months ended December 31, 2022 (2021 – $63 million expense) and $73 million expense for the year ended December 31, 2022 (2021 – $86 million recovery) (2020 - $8 million recovery).
(2) Net of income tax expense of nil for the three months and year ended December 31, 2022 (2021 – nil) (2020 – $1 million expense).
(3) 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 Consolidated Statements of Income.
(4) Net of income tax expense of $276 million for the year ended December 31, 2020.

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, impairment charges, the NSPML unrecoverable costs, and the 2020 gain on sale of Emera Maine.

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

For the millions of dollars	Three months ended December 31 2022	2021	Year ended December 31 2022	2021	2020
Net income (1)	**$ 499**	$ 338	**$ 1,009**	$ 561	$ 984
Interest expense, net	**206**	151	**709**	611	679
Income tax expense (recovery)	**154**	85	**185**	(6)	341
Depreciation and amortization	**254**	227	**952**	902	881
EBITDA	**$ 1,113**	$ 801	**$ 2,855**	$ 2,068	$ 2,885
MTM gain (loss), excluding income tax	**431**	219	**248**	(299)	(18)
Impairment charges, excluding income tax	**(73)**	-	**(73)**	-	(25)
NSPML unrecoverable costs (2)	**-**	-	**(7)**	-	-
Gain on sale, net of transaction costs (excluding income tax)	**-**	-	**-**	-	585
Adjusted EBITDA	**$ 755**	$ 582	**$ 2,687**	$ 2,367	$ 2,343

(1) Net income 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 Consolidated Statements of Income.

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

GBPC Impairment Charge

In Q4 2022, Emera recognized a goodwill impairment charge of $73 million ($0.27 per common share) for GBPC due to a decline in the fair value of the reporting unit. Although the cash flows of GBPC have not changed significantly compared to previous periods, the decline in the fair value was driven by the effects of macro-economic factors on discount rate calculations, including the risk-free rate assumption. This non-cash charge was recorded in “Impairment charge” on the Consolidated Statements of Income and reduced the GBPC goodwill balance to nil. For further details, refer to note 22 in the consolidated financial statements.

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

On December 15, 2022, a payment of $63 million ($45 million after tax and legal costs, or $0.17 per common share), was made by the Republic of Guatemala to TECO Energy in satisfaction of the second and final award issued by the International Centre of the Settlement of Investment Disputes tribunal regarding a dispute over an investment of TGH, a wholly owned subsidiary of TECO Energy. The dispute related to the 2007 intervention by the government of Guatemala in an ongoing independent rate-setting process to unilaterally set a new and lower tariff. The payment was recognized in ‘Other income, net” on the Consolidated Statements of Income. For further details, refer to note 27 in the consolidated financial statements.

Earnings Impact of MTM Gain (Loss), After-Tax

MTM gain, after-tax increased $151 million to $307 million in Q4 2022, compared to $156 million in Q4 2021, and for the year ended December 31, increased $388 million to $175 million compared to a MTM loss, after-tax of $213 million for the same period in 2021. These increases were due to changes in existing positions and reversal of losses in 2022, partially offset by higher amortization in 2022 of gas transportation assets at Emera Energy.

Consolidated Financial Highlights

For the millions of dollars	Three months ended December 31		Year ended December 31		
Adjusted net income	**2022**	2021	**2022**	2021	2020
Florida Electric Utility	**$ 124**	$ 85	**$ 596**	$ 462	$ 501
Canadian Electric Utilities	**46**	67	**222**	241	221
Gas Utilities and Infrastructure	**72**	55	**221**	198	162
Other Electric Utilities	**8**	5	**29**	20	33
Other	**(1)**	(44)	**(218)**	(198)	(252)
Adjusted net income	**$ 249**	$ 168	**$ 850**	$ 723	$ 665
MTM gain (loss), after-tax	**307**	156	**175**	(213)	(10)
Impairment charges, after-tax	**(73)**	-	**(73)**	-	(26)
NSPML unrecoverable costs	**-**	-	**(7)**	-	-
Gain on sale, after tax and transaction costs	**-**	-	**-**	-	309
Net income attributable to common shareholders	**$ 483**	$ 324	**$ 945**	$ 510	$ 938

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

For the millions of dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2021	**$ 168**	**$ 723**
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	39	134
Increased earnings at Emera Energy Services ("EES") due to favourable market conditions	21	21
Increased earnings at PGS due to higher off-system sales and customer growth, partially offset by higher OM&G. Year-over-year also increased due to reversal of accumulated depreciation as a result of the rate case settlement	2	10
Increased earnings at Seacoast due to commencement of a 34-year pipeline lateral lease in 2022	2	9
Increased earnings at NMGC were primarily due to higher asset optimization revenues. Year-over-year increased earnings were partially offset by higher OM&G and increased depreciation	11	4
Decreased earnings at NSPI due to higher OM&G primarily due to increased costs for storm restoration, IT, power generation, regulatory affairs, and higher depreciation. This was partially offset by higher sales volumes. Quarter-over-quarter also decreased due to unfavourable weather	(20)	(10)
Corporate		
TGH award, after tax and legal costs, in Q4 2022. Refer to the "Significant Items Affecting Earnings" section	45	45
Increased income tax recovery primarily due to increased losses before provision for income taxes	17	34
Increased OM&G, pre-tax, due to the timing of long-term compensation and related hedges	(19)	(55)
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	(9)	(28)
Increased interest expense, pre-tax, due to higher interest rates and increased total debt	(17)	(27)
Increased preferred stock dividends due to issuance of preferred shares in 2021	(2)	(13)
Other Variances	11	3
Adjusted net income – 2022	**$ 249**	**$ 850**

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

For the millions of dollars	2022	Year ended December 31 2021	2020
Operating cash flow before changes in working capital	**$ 1,147**	$ 1,337	$ 1,420
Change in working capital	**(234)**	(152)	217
Operating cash flow	**$ 913**	$ 1,185	$ 1,637
Investing cash flow	**$ (2,569)**	$ (2,332)	$ (1,224)
Financing cash flow	**$ 1,555**	$ 1,311	$ (372)

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

As at millions of dollars	2022	December 31 2021	2020
Total assets	**$ 39,742**	$ 34,244	$ 31,234
Total long-term debt (including current portion)	**$ 16,318**	$ 14,658	$ 13,721

Consolidated Income Statement Highlights

For the millions of dollars (except per share amounts)	Three months ended December 31 2022	 2021	 Variance	Year ended December 31 2022	 2021	 Variance	Year ended December 31 2020
Operating revenues	**$ 2,358**	$ 1,868	$ 490	**$ 7,588**	$ 5,765	$ 1,823	$ 5,506
Operating expenses	**1,638**	1,352	(286)	**5,959**	4,835	(1,124)	4,359
Income from operations	**$ 720**	$ 516	$ 204	**$ 1,629**	$ 930	$ 699	$ 1,147
Net income attributable to common shareholders	**$ 483**	$ 324	$ 159	**$ 945**	$ 510	$ 435	$ 938
Adjusted net income	**$ 249**	$ 168	$ 81	**$ 850**	$ 723	$ 127	$ 665
Weighted average shares of common stock outstanding (in millions) (1)	**269.0**	260.8	8.2	**265.5**	257.2	8.3	247.8
EPS – basic	**$ 1.80**	$ 1.24	$ 0.56	**$ 3.56**	$ 1.98	$ 1.58	$ 3.78
EPS – diluted	**$ 1.80**	$ 1.20	$ 0.60	**$ 3.55**	$ 1.98	$ 1.57	$ 3.78
Adjusted EPS – basic	**$ 0.93**	$ 0.64	$ 0.29	**$ 3.20**	$ 2.81	$ 0.39	$ 2.68
Adjusted EBITDA	**$ 755**	$ 582	$ 173	**$ 2,687**	$ 2,367	$ 320	$ 2,343
Dividends per common share declared	**$ 0.6900**	$ 0.6625	$ 0.0275	**$ 2.6775**	$ 2.5750	$ 0.1025	$ 2.4750
Dividends per first preferred shares declared:							
Series A				**$ 0.5456**	$ 0.5456	$ -	$ 0.6155
Series B				**$ 0.6869**	$ 0.4873	$ 0.1996	$ 0.6965
Series C				**$ 1.1802**	$ 1.1802	$ -	$ 1.1802
Series E				**$ 1.1250**	$ 1.1250	$ -	$ 1.1250
Series F				**$ 1.0505**	$ 1.0505	$ -	$ 1.0535
Series H				**$ 1.2250**	$ 1.2250	$ -	$ 1.2250
Series J				**$ 1.0625**	$ 0.6470	$ 0.4155	$ -
Series L				**$ 1.1500**	$ 0.1638	$ 0.9862	$ -

(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 Q4 2022, operating revenues increased $490 million compared to Q4 2021 and, absent increased MTM gains of $195 million, increased $295 million. For the year ended December 31, 2022, operating revenues increased $1,823 million compared to 2021 and, absent increased MTM gains of $555 million, increased by $1,268 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; higher off-system sales and customer growth at PGS; and increased marketing and trading margin due to favourable market conditions at EES. Year-over-year also increased due to increased sales volumes at NSPI and favourable weather at Tampa Electric.

Operating Expenses

For Q4 2022, operating expenses increased $286 million compared to Q4 2021 and, absent the GBPC impairment charge of $73 million, increased by $213 million. For the year ended December 31, 2022, operating expenses increased $1,124 million compared to 2021 and, absent the GBPC impairment charge of $73 million, increased by $1,051 million. The increases in both periods were due to: higher natural gas prices at NMGC and PGS; the impact of a weaker CAD; and increased OM&G at Tampa Electric, Corporate, NSPI, NMGC and PGS. Year-over-year also increased due to higher natural gas and fuel prices at Tampa Electric and BLPC.

Other Income, Net

Other income, net increased for Q4 2022 and the year ended December 31, 2022, compared to the same periods in 2021, primarily due to the TGH award in Q4 2022.

Net Income and Adjusted Net Income

Net income attributable to common shareholders for Q4 2022, as compared to Q4 2021, was favourably impacted by the $151 million increase in MTM gains, after-tax and unfavourably impacted by the $73 million GBPC impairment charge. Absent these changes, adjusted net income increased $81 million. The increase was primarily due to: the TGH award in Q4 2022; higher earnings contribution from Tampa Electric, Emera Energy and NMGC; and the impact of a weaker CAD. These were partially offset by lower earnings contribution from NSPI and increased corporate OM&G due to the timing of long-term compensation and related hedges, and higher corporate interest expense.

Net income attributable to common shareholders for the year ended 2022, as compared to the same period in 2021, was favourably impacted by the $388 million increase in MTM gains, after-tax and unfavourably impacted by the $73 million GBPC impairment charge as well as the $7 million in NSPML unrecoverable costs. Absent these changes, adjusted net income increased $127 million. The increase was primarily due to: higher earnings contributions from Tampa Electric, Emera Energy, PGS and Seacoast; the TGH award in Q4 2022; 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, higher corporate interest expense, realized gains on corporate FX hedges in 2021, increased preferred stock dividends and lower earnings contribution from NSPI.

EPS and Adjusted EPS – Basic

EPS and Adjusted EPS – basic were higher for Q4 2022, and for the year ended December 31, 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 FX hedges entered into to hedge USD denominated operating unit 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:

	Three months ended December 31		Year ended December 31	
	2022	2021	**2022**	2021
Weighted average CAD/USD	**$ 1.37**	$ 1.26	**$ 1.34**	$ 1.26
Period end CAD/USD exchange rate	**$ 1.35**	$ 1.27	**$ 1.35**	$ 1.27

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

For the	Three months ended December 31		Year ended December 31	
millions of USD	**2022**	2021	**2022**	2021
Florida Electric Utility	**$ 91**	$ 67	**$ 458**	$ 369
Other Electric Utilities	**7**	4	**23**	16
Gas Utilities and Infrastructure (1)	**45**	37	**143**	130
Other segment (2)	**30**	(20)	**(50)**	(98)
Total (3)	**$ 173**	$ 88	**$ 574**	$ 417

(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) Excludes $222 million USD in MTM gain, after-tax, for the three months ended December 31, 2022 (2021 – $122 million USD MTM gain, after-tax) and MTM gain, after-tax of $130 million USD for the year ended December 31, 2022 (2021 – $164 million USD MTM loss, after-tax) and the GBPC impairment charge of $54 million USD for the three months and year ended December 31, 2022 (2021 - nil).

The impact of the weakening CAD, partially offset by the unrealized losses on FX hedges increased net income by $42 million in Q4 2022 and $30 million for the year ended December 31, 2022, compared to the same periods in 2021. Weakening of the CAD increased adjusted net income by $14 million in Q4 2022 and $28 million for the year ended December 31, 2022, compared to the same periods in 2021. Impacts of the weakening CAD include the impacts of corporate FX hedges in the Other segment.

BUSINESS OVERVIEW AND OUTLOOK

Florida Electric Utility

Florida Electric Utility consists of Tampa Electric, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida. Tampa Electric has $12.1 billion USD of assets and approximately 827,000 customers at December 31, 2022. Tampa Electric owns 6,549 megawatts ("MW") of generating capacity, of which 78 per cent is natural gas-fired, 15 per cent is solar and 7 per cent is coal. Tampa Electric owns 2,171 kilometres of transmission facilities and 19,916 kilometres of distribution facilities. Tampa Electric meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

Tampa Electric's approved regulated ROE range is 9.25 per cent to 11.25 per cent, based on an allowed equity capital structure of 54 per cent. An ROE of 10.20 per cent will be used for the calculation of the return on investments for clauses.

Tampa Electric anticipates earning within its ROE range in 2023. New base rates effective January 1, 2023, as a result of the 2021 settlement agreement, will result in higher 2023 USD earnings than in 2022. Normalizing 2022 for weather, Tampa Electric sales volumes in 2023 are projected to be higher than in 2022 due to customer growth. Tampa Electric expects customer growth rates in 2023 to be comparable to 2022, reflective of the current expected economic growth in Florida.

On January 23, 2023, Tampa Electric requested an adjustment to its fuel charges to recover the 2022 fuel under-recovery of $518 million USD over a period of 21 months. The request also included an adjustment to 2023 projected fuel costs to reflect the reduction in natural gas prices since September 2022 for a projected reduction of $170 million USD for the balance of 2023. The proposed changes will be decided by the FPSC in March 2023, and recovery is expected to begin in April 2023.

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 were charged against Tampa Electric's FPSC approved storm reserve, resulting in minimal impact to earnings for 2022. The total cost of restoration was $126 million USD, with approximately $119 million USD charged to the storm reserve. Total restoration costs charged to the storm reserve have exceeded the reserve balance and have been deferred as a regulatory asset for future recovery. On January 23, 2023, Tampa Electric petitioned the FPSC 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 $131 million USD. The proposed changes will be decided by the FPSC in March 2023, and recovery is expected to begin in April 2023 through March 2024.

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 was spread over customer bills from April 1, 2022 through December 2022.

In 2023, capital investment in the Florida Electric Utility segment is expected to be $1.3 billion USD (2022 – $1.1 billion USD), including allowance for funds used during construction ("AFUDC"). Capital projects include solar investments, grid modernization and storm hardening investments.

Canadian Electric Utilities

Canadian Electric Utilities includes NSPI and ENL. NSPI is a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and the primary electricity supplier to customers in Nova Scotia. ENL is a holding company with equity investments in NSPML and LIL: two transmission investments related to the development of an 824 MW hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador.

NSPI

With $6.8 billion of assets and approximately 541,000 customers, NSPI owns 2,420 MW of generating capacity, of which approximately 44 per cent is coal-fired; 28 per cent is natural gas and/or oil; 19 per cent is hydro and wind; 7 per cent is petcoke and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPPs"), which own 546 MW of capacity. NSPI also has rights to 153 MW of Maritime Link capacity, representing Nalcor Energy's ("Nalcor") Nova Scotia Block ("NS Block") delivery obligations, as discussed below. NSPI owns approximately 5,000 kilometres of transmission facilities and 28,000 kilometres of distribution facilities.

NSPI's approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40 per cent of approved rate base.

NSPI anticipates earning near the low end of its allowed ROE range in 2023, and below the allowed range in 2024. NSPI expects earnings and sales volumes to be higher in 2023 than 2022.

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

On November 9, 2022, the Nova Scotia provincial government enacted Bill 212, “Public Utilities Act (amended)”. The legislation limits non-fuel rate increases in NSPI’s 2022 General Rate Application (“GRA”) to the UARB, excluding increases relating to demand side management (“DSM”) 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 Bill 212, “Public Utilities Act (amended)”, include a material reduction in NSPI’s planned capital investments and operating costs over the 2023 through 2024 period. Such deferral of capital investment and operating costs may result in higher customer costs in future periods. The legislation will have a direct and negative impact on the financial performance of NSPI and has had a negative impact on NSPI’s credit quality. For more information on this risk, refer to the “Risk Management and Financial Instruments – Regulatory and Political Risk” section.

On November 24, 2022, NSPI filed with the UARB a comprehensive settlement agreement between NSPI, key customer representatives and participating interest groups (“NSPI Settlement Agreement”) in relation to its GRA filed in January 2022. The NSPI Settlement Agreement was structured to be consistent with the amendments to the Public Utilities Act made under Bill 212, which included a 1.8 per cent cap on non-fuel rate increases for 2023 and 2024. Bill 212, “Public Utilities Act (amended),” is described further above. The NSPI Settlement Agreement also addresses the recovery of fuel costs over the settlement period and establishes a DSM rider. This will result in a combined fuel and non-fuel rate increase of 6.9 per cent each year for 2023 and 2024 and annualized incremental revenue (fuel and non-fuel) of $105 million in 2023 and $115 million in 2024. In addition, any under or over recovery of fuel costs will be addressed through the UARB’s established FAM process. NSPI’s ROE range will continue to be 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40 per cent. The NSPI Settlement Agreement also establishes a storm rider for each of 2023, 2024 and 2025, which gives NSPI the option to apply to the UARB for recovery of costs if major storm restoration expense exceeds approximately $10 million in a given year. On February 2, 2023, NSPI received the UARB’s decision, which substantially approved the NSPI Settlement Agreement as filed. Approved rate increases will be effective as of the date of the decision.

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. The storm had 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 the restoration was approximately $115 million, of which $91 million was capitalized to Property, plant and equipment (“PP&E”) and $24 million deferred to Other long-term assets for future amortization, subject to UARB approval. NSPI intends to submit an application to the UARB requesting to defer the recognition of incremental operating costs related to storm restoration. If the deferral is approved, this balance will be reclassified to “Regulatory assets” and amortized over the UARB approved recognition period.

Energy from renewable sources has increased with Nalcor's NS Block delivery obligations from the Muskrat Falls hydroelectric project ("Muskrat Falls") commencing in 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, Nalcor is obligated to provide 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 it's expected that final commissioning of the LIL will be completed in 2023. During these final stages of commissioning, there will be interruptions in supply, with any resultant delivery shortfalls being delivered on a timely basis in accordance with the Energy and Capacity Agreement. 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 Terawatt hours ("TWh") of energy in any given year and, on average, 1.2 TWh of energy per year through August 31, 2041.

Capital investment for 2023, including AFUDC, is expected to be approximately $375 million (2022 – $540 million). NSPI is primarily investing in capital projects required to support power system reliability and reliable service for customers.

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" section. 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 ("Cap-and-Trade Program") and is subject to the 2019 through 2022 compliance period. NSPI received granted emissions allowances under the Cap-and-Trade Program and is permitted to purchase up to five per cent of the credits available at provincial auctions. Any remaining allowance shortfall requires the purchase of reserve credits directly from the provincial government, which are anticipated to be priced at a premium to provincial auction pricing. Compliance is forecast to be achieved through granted emissions allowances and credit purchases under the Cap-and-Trade Program, including reserve credits. Lower than forecast 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 agreed to provide approximately $165 million of relief from the 2019 through 2022 compliance costs, which was equal to the total cost of compliance forecast at the time of the fuel update submitted by NSPI to the UARB in September 2022 as part of the GRA. Discussions related to the final amount of relief and how this relief will be provided are ongoing. Further, NSPI's regulatory framework provides for the recovery of costs prudently incurred to comply with the Cap-and-Trade Program Regulations pursuant to NSPI's FAM.

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 uses emissions performances standards that vary by fuel type, and a carbon price that will start at $65 per tonne in 2023 and increase by $15 per tonne annually, reaching $170 per tonne by 2030. NSPI's regulatory framework provides for the recovery of costs prudently incurred to comply with carbon pricing programs pursuant to NSPI's FAM.

Nova Scotia Renewable Energy Regulations:
Under the provincially legislated Renewable Energy Regulations, 40 per cent of electric sales must be generated from renewable sources. This standard was predicated on receipt of the full NS Block. Due to the delay of the NS Block, the provincial government provided NSPI with an alternative compliance plan that 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 did not 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

Total equity earnings from NSPML and LIL are expected to be higher in 2023, compared to 2022. Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's 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 service on January 15, 2018, enabling the transmission of energy between Newfoundland and Nova Scotia, improved reliability and ancillary benefits, supporting the efficiency and reliability of energy in both provinces. Nalcor continues to advance towards completion of the LIL, and it's expected final commissioning will be achieved in 2023. Nalcor's NS Block delivery obligations commenced on August 15, 2021, and the NS Block will be delivered over the next 35 years pursuant to the project agreements. As Nalcor is in the final stages of commissioning the LIL, there will be commissioning related interruptions in supply with any resultant delivery shortfalls being delivered on a timely basis in accordance with the Energy and Capacity Agreement.

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

In December 2022, NSPML received UARB approval to collect up to $164 million from NSPI for the recovery of costs associated with the Maritime Link in 2023. This continues to be subject to a holdback of up to $2 million a month, as discussed above. On December 22, 2022, the UARB clarified its earlier direction regarding the holdback and NSPI can now release the holdback to NSPML when 90 per cent of NS Block deliveries, including Supplemental Energy deliveries, is achieved. This enabled NSPI to pay NSPML approximately $4 million of the 2022 holdback. As of December 31, 2022, an additional $14 million in aggregate has been held back by NSPI. Determination of allocation of the $14 million between NSPML and NSPI will be subject to a regulatory process that is expected to commence in early 2023 to review the holdback mechanism.

NSPML does not anticipate any significant capital investment in 2023.

LIL

ENL is a limited partner with Nalcor in LIL. Construction of the LIL is complete and Nalcor is forecasting it will achieve final commissioning in 2023.

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 $740 million, comprised of $410 million in equity contribution and $330 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, which is anticipated in 2023, 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.

Peoples Gas System

With $2.5 billion USD of assets and approximately 468,000 customers, the PGS system includes 24,300 kilometres of natural gas mains and 13,500 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2 billion therms in 2022.

The approved ROE range for PGS is 8.9 per cent to 11.0 per cent, based on an allowed equity capital structure of 54.7 per cent. An ROE of 9.9 per cent is used for the calculation of return on investments for clauses.

New Mexico Gas Company, Inc.

With $2.0 billion USD of assets and approximately 545,000 customers, NMGC's system includes approximately 2,426 kilometres of transmission pipelines and 17,781 kilometres of distribution pipelines. Annual natural gas throughput was approximately 926 million therms in 2022.

The approved ROE for NMGC is 9.375 per cent, on an allowed equity capital structure of 52 per cent.

Gas Utilities and Infrastructure Outlook

Gas Utilities and Infrastructure USD earnings are anticipated to be higher in 2023 than 2022, primarily due to a base rate increase at NMGC, effective January 2023.

PGS expects 2023 rate base growth and USD earnings to be consistent with 2022 as higher revenues from customer growth offset increased interest expenses and the effect of inflation. Increased residential and commercial sales volumes and customer growth are anticipated in 2023. PGS anticipates earning below its allowed ROE range in 2023 primarily due to rate base growth. As a result, on February 3, 2023, PGS notified the FPSC that it is planning to file a base rate proceeding in April 2023 for new rates effective January 2024.

The PGS rate case settlement, which was approved in November 2020, provides the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. Through December 31, 2022, PGS reversed $14 million USD accumulated depreciation. The reversal of the remaining accumulated depreciation is expected to occur over 2023.

NMGC expects 2023 rate base and USD earnings to be higher in 2023 than 2022 due to base rate increases effective January 2023, as discussed below, and rate base growth to expand the distribution system and to continue to reliably serve customers. NMGC anticipates earning near its authorized ROE in 2023 and expects customer growth rates to be consistent with historical trends. NMGC's asset optimization revenues for 2022 were well above the historical average, and may not recur in 2023.

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 rates reflect the recovery of increased operating costs and capital investments in pipelines and related infrastructure. The NMPRC approved the settlement agreement on November 30, 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 2023, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $475 million USD (2022 – $436 million USD), including AFUDC. PGS will make investments to expand its system and support customer growth. NMGC will continue to make investments to maintain the reliability of its system and support customer growth.

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 Utilities segment in Q1 2022. The sale did not have a material impact on earnings.

BLPC

With $505 million USD of assets and approximately 133,000 customers, BLPC owns 276 MW of generating capacity, of which 96 per cent is oil-fired and four per cent is solar. BLPC owns approximately 188 kilometres of transmission facilities and 3,789 kilometres of distribution facilities. BLPC's approved regulated return on rate base for 2022 was 10 per cent.

GBPC

With $338 million USD of assets and approximately 19,000 customers, GBPC owns 98 MW of oil-fired generation, approximately 90 kilometres of transmission facilities and 670 kilometres of distribution facilities. GBPC's approved regulatory return on rate base for 2023 is 8.32 per cent (2022 – 8.23 per cent).

Other Electric Utilities Outlook

Absent the impact of the GBPC impairment charge in Q4 2022, Other Electric Utilities' USD earnings in 2023 are expected to increase over the prior year primarily as a result of higher earnings due to higher base rates at BLPC.

BLPC currently operates pursuant to a franchise to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation amending the number of licenses required for the supply of electricity from a single integrated license which currently exists, to multiple licenses for Generation, Transmission and Distribution, Storage, Dispatch and Sales. In March 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The new licenses are expected to take effect in 2023 on completion of the legislative process. The Dispatch license will have a term of five years with the remaining licenses having terms ranging from 25-30 years. BLPC anticipates that any increased costs associated with the implementation of the new multi-licensed structure will be recoverable through BLPC's regulatory framework. BLPC is awaiting final enactment and will work towards implementation of the licenses once received.

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 toward 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 and approximately $1 million USD per month for 2023. Interim rate relief is effective from September 16, 2022 until the implementation of final rates. The hearing concluded in October 2022. On February 15, 2023, the FTC issued a decision on the BLPC rate review application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities of approximately $70 million USD related to the self-insurance fund, accumulated depreciation, and taxes. The impacts to BLPC's rate base and final rates are not yet determinable but management does not expect the decision to have a material impact on Emera's adjusted net income. BLPC will seek to clarify aspects of the FTC decision in its compliance filing and is also considering filing a submission to the FTC for a review of the decision. BLPC expects a decision on final rates from the FTC in 2023.

On January 14, 2022, the GBPA issued its decision on GBPC's rate application. The decision, which became effective April 1, 2022, allows for an increase in revenues of $3.5 million USD. The new rates include a regulatory ROE of 12.84 per cent.

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.

In 2023, capital investment in the Other Electric Utilities segment is expected to be approximately $65 million USD (2022 – $48 million USD), primarily in more efficient and cleaner sources of generation, including renewables and battery storage.

Other

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

Business operations in 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 per cent joint venture ownership of Bear Swamp, a 660 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 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).

Absent the TGH award in Q4 2022, the adjusted net loss from the Other segment is expected to be higher in 2023, based on EES returning to its normal earnings range in 2023 and increased interest expense. The increase is expected to be partially offset by decreased taxes due to a higher net loss.

The Other segment does not anticipate any significant capital investment in 2023.

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

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

millions of dollars		Increase (Decrease)	Explanation
Assets			
Cash and cash equivalents	**$**	**(84)**	Decreased due to increased investment in PP&E at regulated utilities and dividends on common stock. These were partially offset by proceeds from short-term debt issuance at Emera and Tampa Electric, increased proceeds under committed credit facilities at NSPI and Emera, cash from operations, and issuance of common stock
Inventory		**231**	Increased due to higher commodity prices at Emera Energy and NSPI, increased materials inventory at Tampa Electric and the effect of the FX translation of Emera's foreign affiliates
Derivative instruments (current and long-term)		**95**	Increased due to reversal of 2021 contracts at Emera Energy
Regulatory assets (current and long-term)		**1,054**	Increased due to higher fuel cost recovery clauses at Tampa Electric, increased FAM deferrals, driven mainly by increased Cap-and Trade emissions compliance charges, and increased deferred income tax regulatory assets at NSPI, the effect of the FX translation of Emera's foreign affiliates, recognition of storm reserve asset at Tampa Electric due to restoration costs from Hurricane Ian in excess of the storm reserve liability, and increased pension and post-retirement plan deferrals at Tampa and NSPI. These were partially offset by recovery of gas costs from the NMGC 2021 winter event
Receivables and other assets (current and long-term)		**1,165**	Increased due to higher gas transportation assets and higher trade receivables due to higher commodity prices at Emera Energy, fuel option receivable at NMGC and the effect of the FX translation of Emera's foreign affiliates
PP&E, net of accumulated depreciation and amortization		**2,643**	Increased due to the effect of the FX 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 in 2022
Net investment in direct finance and sales type leases		**101**	Increased due to commencement of the pipeline lease at Seacoast in 2022
Goodwill		**316**	Increased due to the effect of the FX translation of Emera's foreign affiliates, partially offset by the GBPC impairment

millions of dollars	Increase (Decrease)	Explanation
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**$ 2,644**	Increased due to the effect of the FX 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 and Emera
Accounts payable	**540**	Increased due to increased commodity prices at Emera Energy, Tampa Electric and NMGC, the effect of the FX translation of Emera's foreign affiliates, higher cash collateral position on derivative instruments at NSPI, and timing of payments at Tampa Electric and NSPI
Deferred income tax liabilities, net of deferred income tax assets	**386**	Increased due to tax deductions in excess of accounting depreciation related to PP&E, increase in net regulatory assets, decrease in net derivative liabilities, and the effect of the FX translation of Emera's foreign affiliates, partially offset by net increase in tax loss carryforwards
Derivative instruments (current and long-term)	**396**	Increased due to new contracts in 2022, partially offset by reversal of 2021 contracts and changes in existing positions at Emera Energy
Regulatory liabilities (current and long-term)	**218**	Increased due to NMGC gas hedge settlements and the effect of the FX translation of Emera's foreign affiliates, partially offset by decreased storm reserve at Tampa Electric due to restoration costs incurred from Hurricane Ian
Pension and post-retirement liabilities	**(89)**	Decreased due to favourable changes in actuarial assumptions, partially offset by lower investment returns
Other liabilities (current and long-term)	**170**	Increased due to accrued emissions compliance charges at NSPI and the effect of the FX translation of Emera's foreign affiliates
Common stock	**520**	Increased due to Emera's ATM equity program and shares issued under the DRIP
Accumulated other comprehensive income	**553**	Increased due to the effect of the FX translation of Emera's foreign affiliates
Retained earnings	**236**	Increased due to net income in excess of dividends paid.

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 was 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 December 31 **2022**	 2021	Year ended December 31 **2022**	 2021
Operating revenues – regulated electric	**$ 597**	$ 561	**$ 2,523**	$ 2,174
Regulated fuel for generation and purchased power	**$ 201**	$ 212	**$ 832**	$ 713
Contribution to consolidated net income	**$ 91**	$ 67	**$ 458**	$ 369
Contribution to consolidated net income – CAD	**$ 124**	$ 85	**$ 596**	$ 462
Average fuel costs in dollars per MWh	**$ 41**	$ 44	**$ 39**	$ 34

The impact of the change in the FX rate increased CAD earnings for the three months and year ended December 31, 2022, by $10 million and $23 million, respectively.

Net Income

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

For the millions of USD	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2021	**$ 67**	**$ 369**
Increased operating revenues due to higher rates effective January 2022, higher fuel recovery clause revenue as a result of increased fuel costs, and customer growth. Year-over-year also increased due to favourable weather	36	349
Fuel for generation and purchased power decreased in Q4 due to lower natural gas prices quarter-over-quarter. Year-over-year, fuel increased due to higher natural gas prices	11	(119)
Increased OM&G due to timing of deferred clause recoveries. Year-over-year the increase is also due to higher transmission and distribution costs, higher benefit costs and higher insurance costs	(6)	(52)
Increased depreciation and amortization due to additions to facilities and the in-service of generation projects	(5)	(15)
Increased interest expense due to higher interest rates and higher borrowings to support Tampa Electric’s ongoing operations, including fuel under-recoveries, and capital investments	(16)	(32)
Decreased AFUDC earnings due to timing of Big Bend modernization and solar projects	(4)	(10)
Increased income tax expense year-over-year primarily due to increased income before provision for income taxes	-	(36)
Other	8	4
Contribution to consolidated net income – 2022	**$ 91**	**$ 458**

Operating Revenues – Regulated Electric

Annual electric revenues and sales volumes are summarized in the following table by customer class:

	Electric Revenues (millions of USD)		Electric Sales Volumes (Gigawatt hours ("GWh"))	
	2022	2021	**2022**	2021
Residential	**$ 1,381**	$ 1,156	**10,109**	9,941
Commercial	**666**	602	**6,300**	6,144
Industrial	**176**	172	**2,111**	2,122
Other (1)	**300**	244	**2,352**	2,000
Total	**$ 2,523**	$ 2,174	**20,872**	20,207

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

Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

	Production Volumes (GWh)	
	2022	2021
Natural gas	**17,083**	16,142
Purchased power	**1,685**	2,301
Solar	**1,492**	1,252
Coal	**1,325**	1,342
Total	**21,585**	21,037

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

Regulatory Environment

Tampa Electric is regulated by the FPSC and is also subject to regulation by the FERC. The FPSC sets rates at a level that allows utilities such as Tampa Electric to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital. Base rates are determined in FPSC rate setting hearings which can occur at the initiative of Tampa Electric, the FPSC or other interested parties. For further details on Tampa Electric's regulatory environment, base rates and recovery mechanisms, refer to note 7 in the consolidated financial statements.

Canadian Electric Utilities

For the millions of dollars (except as indicated)	Three months ended December 31 **2022**	 2021	Year ended December 31 **2022**	 2021
Operating revenues – regulated electric	**$ 421**	$ 389	**$ 1,675**	$ 1,501
Regulated fuel for generation and purchased power (1)	**$ 173**	$ 263	**$ 950**	$ 817
Contribution to consolidated adjusted net income	**$ 46**	$ 67	**$ 222**	$ 241
NSPML unrecoverable costs	**$ -**	$ -	**$ (7)**	$ -
Contribution to consolidated net income	**$ 46**	$ 67	**$ 215**	$ 241
Average fuel costs in dollars per MWh	**$ 61**	$ 93	**$ 85**	$ 75

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

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

For the millions of dollars		Three months ended December 31 **2022**		2021		Year ended December 31 **2022**		2021
NSPI	**$**	**23**	$	43	**$**	**131**	$	141
Equity investment in LIL		**15**		14		**55**		51
Equity investment in NSPML (1)		**8**		10		**36**		49
Contribution to consolidated adjusted net income	**$**	**46**	$	67	**$**	**222**	$	241

(1) Excludes $7 million in NSPML unrecoverable costs, after-tax, for the year ended December 31, 2022 (2021 – nil).

Net Income

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

For the millions of dollars		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2021	**$**	**67**	**$**	**241**
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 electricity pricing effective January 1, 2022. Quarter-over-quarter increase partially offset by unfavourable weather		32		174
Decreased regulated fuel for generation and purchased power quarter-over-quarter due to lower Cap-and-Trade Program provision and lower Maritime Link assessment costs. Increased regulated fuel for generation and purchased power year-over year due to increased Nova Scotia Cap-and-Trade program provision, increased commodity prices and higher sales volume, partially offset by a favourable change in generation mix		90		(133)
Decreased FAM and fixed cost deferrals year-over-year due to increased recovery of fuel costs, partially offset by increased Cap-and-Trade provision. Quarter-over-quarter decreased due to increased recovery of fuel costs and decreased Cap-and-Trade provision		(120)		(16)
Increased OM&G due to higher costs for storm restoration, IT, power generation, and regulatory affairs		(20)		(47)
Increased depreciation and amortization due to increased PP&E in-service		(5)		(13)
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 income before provision for income taxes. This was partially offset by the benefit of tax loss carryforwards recognized as a deferred income tax regulatory liability		7		18
Year-over-year decrease in net income from equity investment in NSPML primarily due to the Maritime Link holdback		(2)		(13)
NSPML unrecoverable costs		-		(7)
Other		(3)		11
Contribution to consolidated net income – 2022	**$**	**46**	**$**	**215**

NSPI

Operating Revenues – Regulated Electric

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

	Electric Revenues (millions of dollars)		Electric Sales Volumes (GWh)	
	2022	2021	**2022**	2021
Residential	**$ 834**	$ 797	**4,822**	4,661
Commercial	**427**	407	**3,006**	2,902
Industrial	**353**	237	**2,480**	2,480
Other	**28**	27	**148**	153
Total	**$ 1,642**	$ 1,468	**10,456**	10,196

Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

	Production Volumes (GWh)	
	2022	2021
Coal	**3,771**	4,623
Natural gas	**1,650**	1,673
Purchased power – other	**910**	865
Petcoke	**897**	519
Oil	**251**	81
Total non-renewables	**7,479**	7,761
Purchased power	**2,423**	1,977
Wind and hydro	**1,105**	1,007
Biomass	**127**	160
Total renewables	**3,655**	3,144
Total production volumes	**11,134**	10,905

NSPI's fuel costs are affected by commodity prices and generation mix, which is largely dependent on economic dispatch of the generating fleet. NSPI brings the lowest cost options on stream first after renewable energy from IPPs, including Community Feed-in Tariff ("COMFIT") participants, for which NSPI has power purchase agreements in place, and the NS Block of energy, including the Supplemental Energy Block. NSPI pays annual assessments approved by the UARB to NSPML for use of the Maritime Link, and therefore utilizes all transmitted NS Block and Supplemental Energy Block energy received which carries no additional fuel cost.

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

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

The provision for the Cap-and-Trade program was an $18 million recovery for the three months ended December 31, 2022 (2021 - $35 million expense) and a $134 million expense for the year ended December 31, 2022 (2021 - $38 million expense). For further information on this non-cash accrual, the estimated costs and the FAM regulatory balance, refer to note 7 in the consolidated financial statements.

Regulatory Environment - NSPI

NSPI is a public utility as defined in the Public Utilities Act and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings held from time to time at NSPI's or the UARB's request. For further details on NSPI's regulatory environment and recovery mechanisms, refer to note 7 in the consolidated 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 December 31 **2022**	 2021	Year ended December 31 **2022**	 2021
Operating revenues – regulated gas (1)	**$ 372**	$ 307	**$ 1,296**	$ 1,006
Operating revenues – non-regulated	**2**	2	**12**	12
Total operating revenue	**$ 374**	$ 309	**$ 1,308**	$ 1,018
Regulated cost of natural gas	**$ 181**	$ 139	**$ 614**	$ 375
Contribution to consolidated net income	**$ 53**	$ 44	**$ 170**	$ 157
Contribution to consolidated net income – CAD	**$ 72**	$ 55	**$ 221**	$ 198

(1) Operating revenues – regulated gas includes $13 million of finance income from Brunswick Pipeline (2021 – $12 million) for the three months ended December 31, 2022 and $47 million (2021 – $46 million) for the year ended December 31 2022; however, it is excluded from the gas revenues and cost of natural gas analysis below.

Gas Utilities and Infrastructure's contribution to consolidated net income is summarized in the following table:

For the millions of USD	Three months ended December 31 **2022**	 2021	Year ended December 31 **2022**	 2021
PGS	**$ 17**	$ 17	**$ 82**	$ 77
NMGC	**22**	15	**35**	33
Other	**14**	12	**53**	47
Contribution to consolidated net income	**$ 53**	$ 44	**$ 170**	$ 157

The impact of the change in the FX rate increased CAD earnings for the three months and year ended December 31, 2022, by $4 million and $6 million, respectively.

Net Income

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

For the millions of USD		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2021	**$**	**44**	**$**	**157**
Increased gas revenues due to higher purchased gas adjustment clause revenues at NMGC and PGS as a result of higher gas prices, higher off-system sales, and customer growth at PGS		55		280
Increased asset optimization revenues at NMGC. In 2022, NMGC's 30 per cent share of asset optimization revenues were well above the historical average, and may not reoccur in 2023		10		10
Increased cost of natural gas sold due to higher gas prices at NMGC and PGS, and higher off-system sales at PGS		(42)		(239)
Increased OM&G primarily due to higher labour and benefits costs at NMGC and PGS, and higher contractor costs at PGS		(3)		(22)
Increased depreciation and amortization due to asset growth at PGS and NMGC. Year-over-year, the increase was more than offset by the reversal of accumulated depreciation as a result of the rate case settlement at PGS		(2)		6
Increased interest expense due to higher interest rates		(4)		(10)
Increased income tax expense primarily due to increased income before provision for income taxes		(2)		(7)
Other		(3)		(5)
Contribution to consolidated net income – 2022	**$**	**53**	**$**	**170**

Operating Revenues – Regulated Gas

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

		Gas Revenues (millions of USD)			**Gas Volumes (Therms)**	
		2022		2021	**2022**	**2021**
Residential	**$**	**614**	$	510	**421**	405
Commercial		**354**		301	**836**	799
Industrial (1)		**64**		53	**1,429**	1,434
Other (2)		**217**		96	**227**	137
Total (3)	**$**	**1,249**	$	960	**2,913**	2,775

(1) Industrial gas revenue includes sales to power generation customers.
(2) Other gas revenue includes off-system sales to other utilities and various other items.
(3) Total gas revenue excludes $47 million of finance income from Brunswick Pipeline (2021 – $46 million).

Regulated Cost of Natural Gas

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

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

Annual gas sales by type are summarized in the following table:

	Gas Volumes by Type (millions of Therms)	
	2022	2021
Transportation	**2,206**	2,154
System supply	**707**	621
Total	**2,913**	2,775

Regulatory Environments

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

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

For further information on PGS and NMGC's regulatory environment and recovery mechanisms, refer to note 7 in the consolidated financial statements.

Other Electric Utilities

All amounts are reported in USD, unless otherwise stated.

For the millions of USD (except as indicated)	Three months ended December 31 **2022**	2021	Year ended December 31 **2022**	2021
Operating revenues – regulated electric	**$ 98**	$ 98	**$ 398**	$ 355
Regulated fuel for generation and purchased power	**$ 54**	$ 52	**$ 223**	$ 175
Contribution to consolidated adjusted net income	**$ 7**	$ 4	**$ 23**	$ 16
Contribution to consolidated adjusted net income – CAD	**$ 8**	$ 5	**$ 29**	$ 20
GBPC Impairment charge	**$ 54**	$ -	**$ 54**	$ -
Equity securities MTM gain (loss)	**$ 1**	$ 2	**$ (4)**	$ 1
Contribution to consolidated net income	**$ (46)**	$ 6	**$ (35)**	$ 17
Contribution to consolidated net income – CAD	**$ (62)**	$ 7	**$ (48)**	$ 21
Electric sales volumes (GWh)	**301**	330	**1,239**	1,262
Electric production volumes (GWh)	**336**	357	**1,340**	1,359
Average fuel cost in dollars per MWh	**$ 161**	$ 146	**$ 166**	$ 129

The impact of the change in the FX rate increased net loss by $3 million for the three months and year ended December 31, 2022 and had a minimal impact on adjusted net income for the same periods.

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

For the millions of USD	Three months ended December 31 **2022**	2021	Year ended December 31 **2022**	2021
BLPC	**$ 5**	$ 6	**$ 11**	$ 11
GBPC	**1**	-	**10**	8
Other	**1**	(2)	**2**	(3)
Contribution to consolidated adjusted net income	**$ 7**	$ 4	**$ 23**	$ 16

Net Income

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

For the millions of USD	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2021	**$ 6**	**$ 17**
Increased operating revenues - regulated electric year-over-year due to higher fuel revenue at BLPC as a result of higher fuel prices, partially offset by the sale of Domlec in Q1 2022	-	43
Increased fuel for generation and purchased power as a result of higher fuel prices at BLPC	(2)	(48)
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	11	17
Goodwill impairment charge at GBPC	(54)	(54)
Decreased MTM gain on equity securities held in BLPC	(1)	(5)
Other	(6)	(5)
Contribution to consolidated net income – 2022	**$ (46)**	**$ (35)**

Regulatory Environments

BLPC is regulated by the FTC, an independent regulator. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested.

GBPC is regulated by the GBPA. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base.

For further details on BLPC and GBPC's regulatory environments and recovery mechanisms, refer to note 7 in the consolidated financial statements.

Other

For the millions of dollars	Three months ended December 31 **2022**	 2021	Year ended December 31 **2022**	 2021
Marketing and trading margin (1) (2)	**$ 72**	$ 39	**$ 143**	$ 102
Other non-regulated operating revenue	**3**	5	**16**	30
Total operating revenues – non-regulated	**$ 75**	$ 44	**$ 159**	$ 132
Contribution to consolidated adjusted net income (loss)	**$ (1)**	$ (44)	**$ (218)**	$ (198)
MTM gain (loss), after-tax (3)	**304**	154	**179**	(214)
Contribution to consolidated net income (loss)	**$ 303**	$ 110	**$ (39)**	$ (412)

(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 gain, pre-tax of $430 million in Q4 2022 (2021 – $212 million gain) and a gain of $281 million for the year ended December 31, 2022 (2021 – $289 million loss).
(3) Net of income tax expense of $124 million for the three months ended December 31, 2022 (2021 – $63 million expense) and $73 million expense for the year ended December 31, 2022 (2021 – $86 million recovery).

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

For the millions of dollars	Three months ended December 31 **2022**	 2021	Year ended December 31 **2022**	 2021
Emera Energy	**$ 41**	$ 17	**$ 70**	$ 54
Corporate – see breakdown of adjusted contribution below	**(37)**	(57)	**(267)**	(231)
Emera Technologies	**(5)**	(4)	**(18)**	(17)
Other	**-**	-	**(3)**	(4)
Contribution to consolidated adjusted net income (loss)	**$ (1)**	$ (44)	**$ (218)**	$ (198)

MTM Adjustments

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

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

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

Emera Corporate has FX forwards to manage the cash flow risk of forecasted USD cash inflows. Fluctuations in the FX rate result in MTM gains or losses recorded in income.

Net Income

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

For the millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income (loss) – 2021	**$ 110**	**$ (412)**
Increased marketing and trading margin due to weather driven market conditions that increased pricing and volatility, which created profitable opportunities for Emera Energy. Year-over-year increase also reflected sustained higher pricing and volatility	33	41
Increased OM&G, pre-tax, primarily due to the timing of long-term compensation and related hedges	(19)	(55)
Increased interest expense, pre-tax, due to increased interest rates and increased total debt	(17)	(27)
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	(9)	(28)
Increased income tax recovery primarily due to increased losses before provision for income taxes	5	25
Increased preferred stock dividends due to issuance of preferred shares in 2021	(2)	(13)
TGH award, after tax and legal costs	45	45
Increased MTM gain, after-tax, due to change in existing positions and larger reversal of MTM losses in 2022, partially offset by higher amortization of gas transportation assets in 2022 at Emera Energy	150	393
Other	7	(8)
Contribution to consolidated net income (loss) – 2022	**$ 303**	**$ (39)**

Emera Energy

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

Corporate

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

For the millions of dollars	Three months ended December 31 **2022**	 2021	Year ended December 31 **2022**	 2021
Operating expenses (1)	**$ 20**	$ 1	**$ 83**	$ 28
Interest expense	**83**	65	**291**	264
Income tax recovery	**(35)**	(18)	**(109)**	(75)
Preferred dividends	**16**	14	**63**	50
TGH award, after tax and legal costs	**(45)**	-	**(45)**	-
Other (2)(3)	**(2)**	(5)	**(16)**	(36)
Corporate adjusted net loss (4)	**$ (37)**	$ (57)	**$ (267)**	$ (231)

(1) Operating expenses include OM&G and depreciation. In Q4 2021, OM&G and depreciation were offset by a decrease in long-term incentive compensation. The value of long-term incentive compensation and related hedges are impacted by changes in Emera's period end share price.
(2) Other includes realized FX gains and losses on FX hedges entered into to hedge USD denominated operating unit earnings exposure.
(3) Includes a realized, pre-tax net loss of $5 million (2021 – $5 million gain) quarter-to-date and a $6 million loss for the year ended December 31, 2022 (2021 – $18 million gain) on FX hedges, as discussed above.
(4) Excludes a MTM gain, after-tax of $9 million for the three months ended December 31, 2022 (2021 – $3 million loss) and a MTM loss, after-tax of $12 million for the year ended December 31, 2023 (2021 – $14 million loss)

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.

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), mainly focused in Florida. 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 DRIP and ATM program.

Emera has credit facilities with varying maturities that cumulatively provide $4.7 billion of credit, with approximately $1.1 billion undrawn and available at December 31, 2022. The Company was holding a cash balance of $332 million at December 31, 2022. For further discussion, refer to the "Debt Management" section below. For additional information regarding the credit facilities, refer to notes 23 and 25 in the consolidated financial statements.

Consolidated Cash Flow Highlights

Significant changes in the Consolidated Statements of Cash Flows between the years ended December 31, 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 changes in working capital	**1,147**	1,337	(190)
Change in working capital	**(234)**	(152)	(82)
Operating activities	**$ 913**	$ 1,185	$ (272)
Investing activities	**(2,569)**	(2,332)	(237)
Financing activities	**1,555**	1,311	244
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**16**	(1)	17
Cash, cash equivalents, and restricted cash, end of period	**$ 332**	$ 417	$ (85)

Cash Flow from Operating Activities

Net cash provided by operating activities decreased $272 million to $913 million for the year ended December 31, 2022, compared to $1,185 million in 2021.

Cash from operations before changes in working capital decreased $190 million for the year ended December 31, 2022. 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, increased fuel for generation and purchased power at NSPI, and decreased long-term payables due to the Nova Scotia Cap-and-Trade accrued emissions compliance charges being reclassified to other current liabilities as the liability is anticipated to be settled in 2023. This was partially offset by the 2021 deferral of gas costs at NMGC resulting from the extreme cold weather event, increased revenues at Tampa Electric and NSPI, favourable changes in regulatory liabilities due to the NMGC gas hedge settlement, TGH award, and increased marketing and trading margin at Emera Energy.

Changes in working capital decreased operating cash flows by $82 million for the year ended December 31, 2022. This decrease was due to unfavourable changes in accounts receivable at NMGC due to the gas hedge settlement, unfavourable changes in accounts receivable at NSPI, unfavourable changes in cash collateral positions on derivative instruments at NSPI, and the required prepayment of income taxes and related interest at NSPI. This was partially offset by the Nova Scotia Cap-and-Trade accrued emissions compliance charges, favourable changes in cash collateral positions at Emera Energy, and favourable changes in accounts payable at Tampa Electric and NMGC.

Cash Flow used in Investing Activities

Net cash used in investing activities increased $237 million to $2,569 million for the year ended December 31, 2022, compared to $2,332 million in 2021. The increase was due to higher capital investment in 2022.

Capital expenditures for the year ended December 31, 2022, including AFUDC, were $2,646 million compared to $2,420 million in 2021. Details of 2022 capital spending by segment are shown below:

- $1,481 million – Florida Electric Utility (2021 – $1,408 million);
- $518 million – Canadian Electric Utilities (2021 – $374 million);
- $578 million – Gas Utilities and Infrastructure (2021 – $522 million);
- $63 million – Other Electric Utilities (2021 – $111 million); and
- $6 million – Other (2021 – $5 million).

Cash Flow from Financing Activities

Net cash provided by financing activities increased $244 million to $1,555 million for the year ended December 31, 2022, compared to $1,311 million in 2021. This increase was due to higher proceeds of short-term debt at Tampa Electric, proceeds from committed credit facilities at NSPI, and term loan issuance at Emera in 2022. These were partially offset by the issuance of preferred shares in 2021, lower proceeds of long-term debt at Tampa Electric, and net proceeds of long-term debt at NMGC in 2021.

Working Capital

As at December 31, 2022, Emera's cash and cash equivalents were $310 million (2021 – $394 million) and Emera's investment in non-cash working capital was $1,173 million (2021 – $491 million). Of the cash and cash equivalents held at December 31, 2022, $250 million was held by Emera's foreign subsidiaries (2021 – $194 million). A portion of these funds are invested in countries that have certain exchange controls, approvals, and processes for repatriation. Such funds are available to fund local operating and capital requirements unless repatriated.

Contractual Obligations

As at December 31, 2022, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2023	2024	2025	2026	2027	Thereafter	Total
Long-term debt principal	$ 574	$ 1,613	$ 262	$ 3,110	$ 946	$ 9,937	$ 16,442
Interest payment obligations (1)	720	699	653	566	472	6,995	10,105
Transportation (2)	693	516	423	383	367	2,817	5,199
Purchased power (3)	269	243	237	228	243	2,145	3,365
Fuel, gas supply and storage	1,161	282	138	40	5	1	1,627
Capital projects	264	89	4	1	-	-	358
Asset retirement obligations	15	2	2	1	1	415	436
Pension and post-retirement obligations (4)	38	31	31	82	59	178	419
Equity investment commitments (5)	240	-	-	-	-	-	240
Other	154	142	132	49	42	189	708
	$ 4,128	$ 3,617	$ 1,882	$ 4,460	$ 2,135	$ 22,677	$ 38,899

(1) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 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 $144 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(3) Annual requirement to purchase electricity production from IPPs 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 a final equity contribution to the LIL upon its commissioning. Once commissioned, the commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation to the Maritime Link and LIL.

NSPI has a contractual obligation to pay NSPML for 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. In December 2022, the UARB approved the collection of $164 million from NSPI for the recovery of Maritime Link costs in 2023. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

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.

Forecasted Gross Consolidated Capital Expenditures

The 2023 forecasted gross consolidated capital expenditures are as follows:

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Total
Generation	$ 276	$ 120	$ -	$ 36	$ -	$ 432
New renewable generation	402	-	-	4	-	406
Transmission	100	74	-	-	-	174
Distribution	479	121	-	34	-	634
Gas transmission and distribution	-	-	639	-	-	639
Facilities, equipment, vehicles, and other	516	60	-	17	11	604
	$ 1,773	$ 375	$ 639	$ 91	$ 11	$ 2,889

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 2027	$ 900	$ 403	$ 497
TEC (in USD) – Unsecured committed revolving credit facility (1)	December 2026	800	620	180
NSPI – Unsecured committed revolving credit facility	December 2027	800	497	303
Emera – Unsecured non-revolving facility	December 2023	400	400	-
Emera – Unsecured non-revolving facility	August 2023	400	400	-
TEC (in USD) – Unsecured non-revolving facility (2)	December 2023	400	400	-
TECO Finance (in USD) – Unsecured committed revolving credit facility	December 2026	400	355	45
NSPI – Unsecured non-revolving facility	July 2024	400	400	-
NMGC (in USD) – Unsecured revolving credit facility	December 2026	125	45	80
NMGC (in USD) – Unsecured non-revolving facility	March 2024	80	80	-
Other (in USD) – Unsecured committed revolving credit facilities	Various	21	7	14

(1) This facility is available for use by Tampa Electric and PGS. At December 31, 2022, $554 million USD was used by Tampa Electric and $66 million USD was used by PGS.

(2) This facility is available for use by Tampa Electric and PGS. At December 31, 2022, $300 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 December 31, 2022. Emera's significant covenant is listed below:

	Financial Covenant	Requirement	As at December 31, 2022
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.57 : 1

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

Florida Electric Utilities

On December 13, 2022, TEC amended its 364-day non-revolving credit facility to extend the maturity date from December 16, 2022 to December 13, 2023 and reduced the facility amount from $500 million USD to $400 million USD. There were no other significant changes in commercial terms from the prior agreement.

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 December 16, 2022, NSPI amended its revolving operating credit facility to extend the maturity date from December 16, 2026 to December 16, 2027 and increase the amount of the facility from $600 million to $800 million. There were no other significant changes in commercial terms from the prior agreement.

On July 15, 2022, NSPI entered into a $400 million non-revolving term credit facility which matures on July 15, 2024. The credit facility 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 facility were used for general corporate purposes.

Gas Utilities and Infrastructure

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

On June 30, 2022, Brunswick Pipeline amended its non-revolving 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 December 16, 2022, Emera amended its $900 million revolving operating credit facility to extend the maturity date from June 30, 2026 to June 30, 2027. There were no other significant changes in commercial terms from the prior agreement.

On December 16, 2022, Emera amended its $400 million non-revolving term credit facility to extend the maturity from December 16, 2022 to December 16, 2023. There were no other significant changes in commercial terms from the prior agreement.

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 facility were used for general corporate purposes.

Credit Ratings

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

	Fitch (1)	S&P (2)(3)	Moody's (4)(5)	DBRS (6)
Emera Inc.	BBB (Negative)	BBB- (Negative)	Baa3 (Negative)	N/A
TECO Energy/TECO Finance	N/A	N/A	N/A	N/A
TEC	A (Negative)	BBB+ (Negative)	A3 (Negative)	N/A
NMGC	BBB+ (Negative)	N/A	N/A	N/A
NSPI	N/A	BBB- (Negative)	N/A	BBB (high)(stable)

(1) On November 21, 2022, Fitch Ratings ("Fitch") affirmed its BBB issuer rating for Emera Inc. Fitch also affirmed the A- issuer and A unsecured debt ratings for TEC and BBB+ for NMGC. Emera and subsidiaries' outlook was changed to negative from stable.
(2) On November 21, 2022, S&P Global Ratings ("S&P") affirmed its BBB issuer rating for Emera Inc. and TECO Energy, while affirming the BBB+ issuer credit ratings for TEC. S&P downgraded NSPI's issue-level and senior unsecured debt ratings to BBB-. Emera and subsidiaries' outlook remained at negative.
(3) On October 24, 2022, 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.
(4) 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.
(5) 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.
(6) On December 20, 2022, DBRS ("Dominion Bond Rating Service") downgraded its issuer credit and senior unsecured rating for NSPI to BBB (high). NSPI's outlook remained unchanged at stable.

The downgrades from both S&P and DBRS of NSPI were attributed to their view of the enactment of Bill 212, "Public Utilities Act (amended)", as a political intervention in the regulatory process that resulted in an increase in political risk and a reduction in the stability and predictability of NSPI's regulatory environment.

Guaranteed Debt

As of December 31, 2022, the Company had $2.75 billion USD senior unsecured notes ("U.S. Notes") outstanding.

The U.S. Notes are fully and unconditionally guaranteed, on a joint and several basis, by Emera and Emera US Holdings Inc. (in such capacity, the "Guarantor Subsidiaries"). Emera owns, directly or indirectly, all of the limited and general partnership interests in Emera US Finance LP. Other subsidiaries of the Company do not guarantee the U.S. Notes (such subsidiaries are referred to as the "Non-Guarantor Subsidiaries") however, Emera has unrestricted access to the assets of consolidated entities.

In compliance with Rule 13-01 of Regulation S-X, the Company is including summarized financial information for Emera, Emera US Holdings Inc., and Emera US Finance LP (together, the "Obligor Group"), on a combined basis after transactions and balances between the combined entities have been eliminated. Investments in and equity earnings of the Non-Guarantor Subsidiaries have been excluded from the summarized financial information.

The Obligor Group was not determined using geographic, service line or other similar criteria and, as a result the summarized financial information includes portions of Emera's domestic and international operations. Accordingly, this basis of presentation is not intended to present Emera's financial condition or results of operations for any purpose other than to comply with the specific requirements for guarantor reporting.

Summarized Statement of Income (loss)

The Company recognized income related to guaranteed debt under the following categories:

For the millions of dollars	Year ended December 31 2022	2021
Loss from operations	**$ (73)**	$ (21)
Net losses (1)	**$ (131)**	$ (86)

(1) Includes $262 million in interest and dividend income, net, from non-guarantor subsidiaries.

Summarized Balance Sheet

The Company has the following categories on the balance sheet related to guaranteed debt:

As at millions of dollars	December 31 2022	2021
Current assets (1)	**$ 172**	$ 329
Goodwill	**6,012**	5,628
Other assets (2)	**6,402**	6,027
Total assets (3)	**$ 12,586**	$ 11,984
Current liabilities (4)	**$ 1,903**	$ 888
Long-term liabilities (5)	**6,431**	6,403
Total liabilities	**$ 8,334**	$ 7,291

(1) Includes $144 million (2021 – $140 million) in amounts due from non-guarantor subsidiaries.
(2) Includes $6,058 million (2021 – $5,749 million) in amounts due from non-guarantor subsidiaries.
(3) Excludes investments in non-guarantor subsidiaries. Consolidated Emera total assets are $39,742 million (2021 – $34,244 million).
(4) Includes $392 million (2021 – $346 million) due to non-guarantor subsidiaries.
(5) Includes $769 million (2021 – $776 million) due to non-guarantor subsidiaries.

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)	4.07	248
Issued under the DRIP, net of discounts	4.21	238
Senior management stock options exercised and Employee Share Purchase Plan	0.60	34
Balance, December 31, 2022	**269.95**	**$ 7,762**

(1) In Q4 2022, 278,545 common shares were issued under Emera's ATM program at an average price of $54.06 per share for gross proceeds of $15 million ($15 million net of after-tax issuance costs). For the year ended December 31, 2022, 4,072,469 common shares were issued under Emera's ATM program at an average price of $61.31 per share for gross proceeds of $250 million ($248 million net of after-tax issuance costs). As at December 31, 2022, an aggregate gross sales limit of $207 million remained available for issuance under the ATM program.

As at February 16, 2023, the amount of issued and outstanding common shares was 271.4 million.

If all outstanding stock options were converted as at February 16, 2023, an additional 2.9 million common shares would be issued and outstanding.

Preferred Stock

As at February 16, 2023, 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.

PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three-year period. The cash required in 2023 for defined benefit pension plans is expected to be $44 million (2022 – $45 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

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

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

Emera's projected contributions to defined contribution pension plans are $44 million for 2023 (2022 – $41 million).

Defined Benefit Pension Plan Summary

in millions of dollars

Plans by region	**TECO Energy**	**NSPI**	**Caribbean**	**Total**
Assets as at December 31, 2022	$ 880	$ 1,273	$ 10	$ 2,163
Accounting obligation at December 31, 2022	$ 902	$ 1,240	$ 16	$ 2,158
Accounting expense during fiscal 2022	$ 10	$ (3)	$ 1	$ 8

Off-Balance Sheet Arrangements

Defeasance

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2022 totalled $200 million (2021 – $200 million). The securities are held in trust for an affiliate of the Province of Nova Scotia. Approximately 66 per cent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

Guarantees and Letters of Credit

Emera has guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2022:

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

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.

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

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.

NSPI has issued guarantees on behalf of its subsidiary, NS Power Energy Marketing Incorporated ("NSPEMI"), in the amount of $119 million USD (2021 – $118 million USD) with terms of varying lengths.

The Company has standby letters of credit and surety bonds in the amount of $145 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., on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The expiry date of this letter of credit was extended to June 2023. The amount committed as at December 31, 2022 was $63 million (December 31, 2021 – $64 million).

DIVIDEND PAYOUT RATIO

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. Emera's common share dividends paid in 2022 were $2.6775 ($0.6625 in Q1, Q2, and Q3 and $0.6900 in Q4) per common share and $2.5750 ($0.6375 in Q1, Q2, and Q3 and $0.6625 in Q4) per common share for 2021, representing a dividend payout ratio of 75 per cent in 2022 (2021 – 129 per cent) and a dividend payout ratio of adjusted net income of 83 per cent in 2022 (2021 – 91 per cent).

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 quarterly dividend payment at the increased rate was paid on November 15, 2022.

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 Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $157 million for the year ended December 31, 2022 (2021 – $149 million). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments. For further details, refer to the "Business Overview and Outlook - Canadian Electric Utilities – ENL" and "Contractual Obligations" sections.

- Natural gas transportation capacity purchases from M&NP are reported in the Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $9 million for the year ended December 31, 2022 (2021 – $19 million).

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

ENTERPRISE RISK AND RISK MANAGEMENT

Emera has an enterprise-wide risk management process, overseen by its Enterprise Risk Management Committee ("ERMC") and monitored by the Board of Directors, to ensure an effective, consistent and coherent approach to risk management. Certain risk management activities for Emera are overseen by the ERMC to ensure such risks are appropriately identified, assessed, monitored and subject to appropriate controls.

The Board of Directors established a Risk and Sustainability Committee ("RSC") in September 2021. The mandate of the RSC is to assist the Board in carrying out its risk and sustainability oversight responsibilities. The RSC's mandate includes oversight of the Company's Enterprise Risk Management framework, including the identification, assessment, monitoring and management of enterprise risks. It also includes oversight of the Company's approach to sustainability and its performance relative to its sustainability objectives.

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

Regulatory and Political Risk

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

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

Regulators administer legislation covering material aspects of the utilities' businesses, including customer rates and/or riders, the underlying allowed ROEs, deemed capital structures, capital investment, the terms and conditions for the provision of service, performance standards, and affiliate transactions. Costs and investments can be recovered upon approval by the respective regulator as an adjustment to rates and/or riders, which normally require a public hearing process or may be mandated by other governmental bodies. During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these rate-regulated companies, and their respective regulators determine whether to allow recovery and to adjust rates based upon the evidence and any contrary evidence from other parties. In some circumstances, other government bodies may influence the setting of rates. Regulatory decisions, legislative changes, and prolonged delays in the recovery of costs or regulatory assets could result in decreased rate affordability for customers and could materially affect Emera and its utilities.

Emera's utilities generally manage this risk through transparent regulatory disclosure, ongoing stakeholder and government consultation, and multi-party engagement on aspects such as utility operations, regulatory audits, rate filings and capital plans. The subsidiaries employ a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

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

Emera cannot predict future legislative, policy, or regulatory changes, whether caused by economic, political or other factors, or its ability to respond in an effective and timely manner or the resulting compliance costs. Government interference in the regulatory process can undermine regulatory stability, predictability, and independence, and could have a material adverse effect on the Company.

Global Climate Change Risk

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

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

The Company has made significant investments to facilitate the use of renewable and lower-carbon energy including wind generation, the Maritime Link in Atlantic Canada, and in Florida, solar generation and modernization of the Big Bend Power Station. Tampa Electric has taken significant steps to reduce overall emissions at its facilities as a result of its capital investment plan which has and will continue to reduce carbon dioxide emissions. In 2022, NSPI achieved reductions of carbon dioxide emissions of approximately 45 per cent from 2005 levels. NSPI expects to exceed the Canadian target of 40-45 per cent reduction by 2030, as set out in the Canadian Net-Zero Emissions Accountability Act. Both the Government of Nova Scotia and the Government of Canada have enacted or introduced legislation that includes goals of net-zero GHG emissions by 2050. The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix, reductions in GHG emissions, as well as the goal to phase out coal-fired electricity generation by 2030. Failure to meet such goals by 2030 could result in material fines, penalties, other sanctions and adverse reputational impacts. NSPI continues to work with both the provincial and federal governments on measures to seek to address their carbon reduction goals. Future compliance with provincial and federal GHG emission caps, coal phase out requirements and targets, and renewable standards has been challenged as a result of the constraints imposed by the enactment of Bill 212, "Public Utilities Act (amended)". Within Emera's natural gas utilities, there are ongoing efforts to reduce methane and carbon dioxide emissions through replacement of aging infrastructure, more efficient operations, operational and supply chain optimization, and support of public policy initiatives that address the effects of climate change.

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

Physical Impacts

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

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

Reputation

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

Markets

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

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

Policy

Government and regulatory initiatives, including greenhouse gas emissions standards, air emissions standards and generation mix standards, are being proposed and adopted in many jurisdictions in response to concerns regarding the effects of climate change. In some jurisdictions, government policy has included timelines for mandated shutdowns of coal generating facilities, percentage of electricity generation from renewables, carbon pricing, emissions limits and cap and trade mechanisms. Over the medium and longer terms, this could potentially lead to a significant portion of hydrocarbon infrastructure assets being subject to additional regulation and limitations in respect of GHG emissions and operations. The Company is subject to climate-related and environmental legislative and regulatory requirements. Such legislative and regulatory initiatives could adversely affect Emera's operations and financial performance. Refer to "Regulatory and Political Risk" and "Changes in Environmental Legislation" risk. The Company seeks to mitigate these risks through active engagement with governments and regulators to pursue transition strategies that meet the needs of customers, stakeholders and the Company. This has included NSPI's participation in negotiated equivalency agreements in Nova Scotia to provide for an affordable transition to lower-carbon generation. Equivalency agreements allow NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent. There is no guarantee that such equivalency agreements will be renewed or remain in force in the future.

Regulatory

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

Legal

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

Water Resources

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

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

Weather Risk

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

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

Extreme weather events create a risk of physical damage to the Company’s assets. High winds can impact structures and cause widespread damage to transmission and distribution infrastructure, solar generation, and wind powered generation. Increased frequency and severity of weather events increases the likelihood that the duration of power outages and fuel supply disruptions could increase. Increased frequency and intensity of flooding and storm surge could adversely affect the operations of utilities and in particular generation assets. The impact of extreme weather events would be amplified if the same events affect multiple utilities.

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

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

Changes in Environmental Legislation

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

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

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

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

Cybersecurity Risk

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

Cyberattacks can reach the Company's assets and information via their interfaces with third parties or the public internet and gain access to critical infrastructures. Cyberattacks can also occur via personnel with direct access to critical assets or trusted networks. Methods used to attack critical assets could include general purpose or energy-sector-specific malware delivered via network transfer, removable media, viruses, attachments, or links in e-mails. The methods used by attackers are continuously evolving and can be difficult to predict and detect.

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

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

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

Public Health Risk

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

Any adverse changes in general economic and market conditions arising as a result of a public health threat could negatively impact demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; which could result in a material adverse effect on the Company's business. The Company maintains pandemic and business contingency plans in each of its operations to manage and help mitigate the impact of any such public health threat.

Energy Consumption Risk

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

Foreign Exchange Risk

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

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

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

Liquidity and Capital Market Risk

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

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

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

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

General Economic Risk

The Company has exposure to the macro-economic conditions in North America and in other geographic regions in which Emera operates. Like most utilities, economic factors such as consumer income, employment and housing affect demand for electricity and natural gas and, in turn, the Company's financial results. Adverse changes in general economic conditions and inflation may impact the ability of customers to afford rate increases arising from increases to fuel, operating, capital, environmental compliance, and other costs, and therefore could materially affect Emera and its utilities. This may also result in higher credit and counterparty risk, adverse shifts in government policy and legislation, and/or increased risk to full and timely recovery of costs and regulatory assets.

Interest Rate Risk

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk. Emera seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

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

As with most other utilities and other similar yield-returning investments, Emera's share price may be affected by changes in interest rates and could underperform the market in an environment of rising interest rates.

Inflation Risk

The Company may be exposed to changes in inflation that may result in increased operating and maintenance costs, capital investment, and fuel costs compared to the revenues provided by customer rates. Emera's utilities have budgeting and forecasting processes to identify inflationary risk factors and measure operating performance, as well as collective bargaining agreements that mitigate the short-term impact of inflation on labour costs.

Project Development and Land Use Rights Risk

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

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

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

Counterparty Risk

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

Emera manages this counterparty risk through due diligence and third-party risk assessment processes prior to signing contracts, contractual rights and remedies, regulatory frameworks, and by monitoring significant developments with its customers, partners and suppliers. The Company also manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments may be conducted on new customers and counterparties, and deposits or collateral may be requested on certain accounts. There is no assurance that management strategies will be effective, and significant counterparty defaults could have a material effect on the Company.

Country Risk

The majority of Emera’s earnings are from outside of Canada, mostly concentrated in the United States. Emera’s investments are currently in regions where political and economic risks are considered by the Company to be acceptable. For more information, refer to the “Regulatory and Political Risk” and “General Economic Risk” sections above. Emera’s operations in some countries may be subject to changes in economic growth, restrictions on the repatriation of income or capital exchange controls, inflation, the effect of global health, safety and environmental matters, including climate change, or economic conditions and market conditions, and change in financial policy and availability of credit. The Company mitigates this risk through a rigorous approval process for investment, and by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available in all affiliates.

Commodity Price Risk

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

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

Regulated Utilities

The Company's utility fuel supply is exposed to broader global conditions, which may include impacts on delivery reliability and price, despite contracted terms. Supply and demand dynamics in fuel markets can be affected by a wide range of factors which are difficult to predict and may change rapidly, including but not limited to, currency fluctuations, changes in global economic conditions, natural disasters, transportation or production disruptions, and geo-political risks, such as political instability, conflicts, changes to international trade agreements, trade sanctions or embargos. The Company seeks to manage this risk using financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable.

The majority of Emera's regulated electric and gas utilities have adopted and implemented fuel adjustment mechanisms and purchased gas adjustment mechanisms respectively, which further helps manage commodity price risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel and gas costs. There is no assurance that such mechanisms and regulatory frameworks will continue to exist in the future. Prolonged and substantial increases in fuel prices could result in decreased rate affordability, increased risk of recovery of costs or regulatory assets, and/or negative impacts on customer consumption patterns and sales.

Emera Energy Marketing and Trading

Emera Energy has employed further measures to manage commodity risk. The majority of Emera Energy's portfolio of electricity and gas marketing and trading contracts and, in particular, its natural gas asset management arrangements, are contracted on a back-to-back basis, avoiding any material long or short commodity positions. However, the portfolio is subject to commodity price risk, particularly with respect to basis point differentials between relevant markets in the event of an operational issue or counterparty default. Changes in commodity prices can also result in increased collateral requirements associated with physical contracts and financial hedges, resulting in higher liquidity requirements and increased costs to the business.

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

Future Employee Benefit Plan Performance and Funding Risk

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

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

Labour Risk

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

Approximately 32 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have an adverse effect on the Company's earnings, cash flow and financial position. Emera seeks to manage this risk through ongoing discussions and working to maintain positive relationships with local unions. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labour disruption.

IT Risk

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

Emera manages these risks through IT asset lifecycle planning and management, governance, internal auditing and testing of systems, and executive oversight. Employees with extensive subject matter expertise assist in risk identification and mitigation, project management, implementation, change management and training. System resiliency, formal disaster recovery and backup processes, combined with critical incident response practices, table-top exercises, and simulations, help mitigate operational disruptions.

Income Tax Risk

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

System Operating and Maintenance Risks

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

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

Fuel Supply Disruptions

Emera's electric and natural gas utilities are also exposed to the risk of fuel supply chain disruptions, both within and outside their service territories, which may be caused by severe weather or natural disasters. This may also be caused by damage to, operational issues with, terrorist or cyberattacks on, third party fuel production, storage, pipeline, and distribution facilities. The risk of fuel supply disruptions is managed through contractual protections, maintaining a diversity of fuel suppliers and transportation contracts, and contracting for access to third-party storage facilities. Significant unanticipated fuel supply disruptions, such as those which arose from Winter Storm Uri in February 2021, could result in increased exposure to commodity price risk for Emera's regulated electric and gas utilities and Emera Energy, and these could have adverse effects on service to utility customers and on the Company's reputation, earnings, cash flow and financial position.

Uninsured Risk

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

The occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by Emera and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on Emera's results of operations, cash flows and financial position, if regulatory recovery is not available.

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

RISK MANAGEMENT INCLUDING FINANCIAL INSTRUMENTS

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

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

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. Physical contracts that meet the NPNS exception are not recognized on the balance sheet; these contracts are recognized in income when they settle. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty creditworthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

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

Derivatives entered into by NSPI, NMGC and GBPC that are documented as economic hedges or for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled. Management believes any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates. Tampa Electric has no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases which ended on December 31, 2022. Tampa Electric's moratorium on hedging of natural gas purchases will continue through December 31, 2024, as a result of Tampa Electric's 2021 rate case settlement agreement.

Derivatives that do not meet any of the above criteria are designated as HFT, with changes in fair value normally recorded in net income of the period. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

Derivative Assets and Liabilities Recognized on the Balance Sheet

As at millions of dollars	**December 31 2022**	December 31 2021
Regulatory Deferral:		
Derivative instrument assets (1)	**$ 238**	$ 237
Derivative instrument liabilities (2)	**(25)**	(20)
Regulatory assets (1)	**30**	23
Regulatory liabilities (2)	**(230)**	(241)
Net asset (liability)	**$ 13**	$ (1)
HFT Derivatives:		
Derivative instrument assets (1)	**$ 153**	$ 53
Derivatives instruments liabilities (2)	**(1,025)**	(662)
Net liability	**$ (872)**	$ (609)
Other Derivatives:		
Derivative instrument assets (1)	**$ 5**	$ 11
Derivatives instruments liabilities (2)	**(28)**	-
Net asset (liability)	**$ (23)**	$ 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		Year ended December 31 **2022**		2021
Regulatory Deferral:				
Regulated fuel for generation and purchased power (1)	**$**	**210**	$	34
HFT Derivatives:				
Non-regulated operating revenues	**$**	**64**	$	(138)
Other Derivatives:				
OM&G	**$**	**(22)**	$	26
Other income, net		**(24)**		3
Net gains (losses)	**$**	**(46)**	$	29
Total net gains (losses)	**$**	**228**	$	(75)

(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 December 31, 2022, the unrealized gain in AOCI was $16 million, net of tax (2021 – $18 million, net of tax). For the year ended December 31, 2022, unrealized gains of $2 million (2021 – $1 million), have been reclassified into interest expense.

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). The Company's internal control framework is based on the criteria published in the Internal Control - Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations ("COSO") of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design and effectiveness of the Company's DC&P and ICFR as at December 31, 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 year ended December 31, 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 consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring 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 ("ARO"), 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.

Rate Regulation

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

As at December 31, 2022, the Company has recorded $3,620 million (2021 – $2,566 million) of regulatory assets and $2,273 million (2021 – $2,055 million) of regulatory liabilities.

Accumulated Reserve – Cost of Removal

Tampa Electric, PGS, NMGC and NSPI recognize non-ARO costs of removal ("COR") as regulatory liabilities. The non-ARO COR represent estimated funds received from customers through depreciation rates to cover future COR of PP&E upon retirement that are not legally required. The companies accrue for COR over the life of the related assets based on depreciation studies approved by their respective regulators. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays. As at December 31, 2022, the balance of the Accumulated reserve – COR within regulatory liabilities was $895 million (2021 – $819 million).

Pension and Other Post-Retirement Employee Benefits

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

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

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

The Company's accounting policy is to amortize the net actuarial gain or loss that exceeds 10 per cent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period. For the largest plans this is currently 8.3 years (8.7 years for 2022 benefit cost) for the Canadian plans and a weighted average of 11.4 years for the United States plans). The Company's use of smoothed asset values reduces volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

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

	2022		**2021**	
	Discount rate for benefit cost purposes	**Expected return on plan assets**	Discount rate for benefit cost purposes	Expected return on plan assets
TECO Energy Group Retirement Plan	**2.78%**	**6.50%**	2.38%	6.70%
TECO Energy Group Supplemental Executive Retirement Plan (1)	**2.35/5.33%**	**N/A**	1.84%	N/A
TECO Energy Group Benefit Restoration Plan (1)	**2.27/4.19/5.48%**	**N/A**	1.71%	N/A
TECO Energy Post-retirement Health and Welfare Plan	**2.84%**	**N/A**	2.47%	N/A
New Mexico Gas Company Retiree Medical Plan	**2.85%**	**1.50%**	2.49%	4.00%
NSPI	**3.25%, 3.48%**	**5.75%**	2.59%, 2.85%	5.25%
GBPC Salaried	**5.75%**	**6.00%**	4.25%	6.00%
GBPC Union	**5.75%**	**5.35%**	5.65%	5.65%

(1) The discount rate and expected return on assets for benefit cost purposes is updated throughout the year as special events occur, such as settlements and curtailments.

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans was $64 million in 2022 (2021 – $85 million). The reported benefit cost is impacted by numerous assumptions, including the discount rate and asset return assumptions. A 0.25 per cent change in the discount rate and asset return assumptions would have had +/- impact on the 2022 benefit cost of $0.5 million and $1 million respectively (2021 – $1 million and $3 million).

Unbilled Revenue

Electric and gas revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for other Emera utilities. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and determine related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses, inter-period changes to customer classes and applicable customer rates. Based on the extent of estimates included in the determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2022, unbilled revenues totalled $424 million (2021 – $318 million) on total regulated operating revenues of $7,154 million (2021 – $5,926 million).

Property, Plant and Equipment

PP&E represents 58 per cent of total assets on the Company's balance sheet and include the generation, transmission and distribution, and other assets of the Company.

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

Depreciation expense was $927 million for the year ended December 31, 2022 (2021 – $877 million).

Goodwill Impairment Assessments

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated fair values of identifiable assets acquired, and liabilities assumed at the acquisition date. Goodwill is carried at initial cost less any write-down for impairment and is adjusted for the impact of foreign exchange. Under the applicable accounting guidance, goodwill is subject to assessment for impairment at the reporting unit level annually, or if an event or change in circumstances indicates that the fair value of a reporting unit may be below its carrying value. Application of the goodwill impairment test requires management judgment on significant assumptions and estimates. When assessing goodwill for impairment, the Company has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment management considers, among other factors, macroeconomic conditions, industry and market considerations and overall financial performance.

If the Company performs the qualitative assessment and determines that it is more likely than not that its fair value is less than its carrying amount, or if the Company chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, an impairment loss is recorded. Significant assumptions used in estimating the fair value include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting units' net operating loss ("NOL") and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera's reporting units.

As of December 31, 2022, $6,009 million of Emera's goodwill represents the excess of the acquisition purchase price for TECO Energy (Tampa Electric, PGS and NMGC reporting units) over the fair values assigned to identifiable assets acquired and liabilities assumed. In Q4 2022, qualitative assessments were performed for Tampa Electric and PGS given the significant excess of fair value over carrying amounts calculated during the last quantitative test in Q4 2019. Management concluded it was more likely than not that the fair value of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required. For the NMGC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment using a combination of the income and market approach. This assessment estimated that the fair value of the NMGC reporting unit exceeded its carrying amount, including goodwill. As a result of this assessment, no impairment charges were recognized.

In Q4 2022, the Company elected to bypass a qualitative assessment and performed a quantitative impairment assessment for GBPC, using the income approach, as this reporting unit is sensitive to changes in assumptions due to limited excess of fair value over the carrying value, including goodwill. Although the cash flows of GBPC have not changed significantly compared to previous periods, it was determined that the carrying value, including goodwill, exceeded the fair value, due to an increase in discount rates. The discount rate for the reporting unit was negatively impacted by changes in the macro-economic environment, including the risk-free rate assumption. As a result of this assessment, a goodwill impairment charge of $73 million was recorded in 2022, reducing the GBPC goodwill balance to nil as at December 31, 2022. No impairment was recorded in 2021. For further detail, refer to note 22.

As of December 31, 2022, the Company had goodwill with a total carrying amount of $6,012 million (December 31, 2021 – $5,696 million). The change in the carrying value of goodwill from 2021 to 2022 was a result of the effect of the FX translation of Emera's foreign affiliates, partially offset by the GBPC impairment.

Long-Lived Assets Impairment Assessments

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

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

As at December 31, 2022, there were no indications of impairment of Emera's long-lived assets. No impairment charges were recognized in either 2022 or 2021.

Income Taxes

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

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

Asset Retirement Obligations

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

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

Some of the Company's transmission and distribution assets may have conditional AROs which are not recognized in the consolidated financial statements as the fair value of these obligations could not be reasonably estimated given there is insufficient information to do so. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at fair value when an amount can be determined.

As at December 31, 2022, AROs recorded on the balance sheet were $174 million (2021 – $174 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $429 million (2021 – $422 million), which will be incurred between 2023 and 2061. The majority of these costs will be incurred between 2028 and 2050.

Financial Instruments

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

Level Determinations and Classifications

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

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policy that is applicable to, and adopted by the Company in 2022, is described as follows:

Facilitation of the Effects of Reference Rate Reform on Financial Reporting

The Company adopted Accounting Standard Update ("ASU") 2022-06, *Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848* in Q4 2022. The update extends the period of time preparers can utilize the reference rate reform relief guidance issued under ASU 2020-04, which was adopted by the Company in Q4 2020. The guidance in ASU 2022-06 was effective as of the date of issuance and entities may elect to apply the guidance prospectively through to December 31, 2024. The Company has applied the guidance permitted by ASU 2020-04 to certain debt agreements that were amended during the current period. The Company's transition from reference rates will not have a material impact on the consolidated financial statements.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs 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 consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q4 2022**	Q3 2022	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021
Operating revenues	**$ 2,358**	$ 1,835	$ 1,380	$ 2,015	$ 1,868	$ 1,148	$ 1,137	$ 1,612
Net income (loss) attributable to common shareholders	**$ 483**	$ 167	$ (67)	$ 362	$ 324	$ (70)	$ (17)	$ 273
Adjusted net income	**$ 249**	$ 203	$ 156	$ 242	$ 168	$ 175	$ 137	$ 243
EPS – basic	**$ 1.80**	$ 0.63	$ (0.25)	$ 1.38	$ 1.24	$ (0.27)	$ (0.07)	$ 1.08
EPS – diluted	**$ 1.80**	$ 0.63	$ (0.25)	$ 1.38	$ 1.20	$ (0.27)	$ (0.07)	$ 1.08
Adjusted EPS – basic	**$ 0.93**	$ 0.76	$ 0.59	$ 0.92	$ 0.64	$ 0.68	$ 0.54	$ 0.96

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.