Emera

Management’s Discussion & Analysis

As at May 12, 2022

Management’s Discussion & Analysis (“MD&A”) provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments during the first quarter of 2022 relative to the same quarter in 2021; and its financial position as at March 31, 2022 relative to December 31, 2021. Throughout this discussion, “Emera Incorporated”, “Emera” and “Company” refer to Emera Incorporated and all of its consolidated subsidiaries and investments. The Company’s activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

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

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

Emera Rate-Regulated Subsidiary or Equity	**Accounting Policies Approved/Examined By**
Subsidiary	
Tampa Electric – Electric Division of Tampa Electric Company (“TEC”)	Florida Public Service Commission (“FPSC”) and the Federal Energy Regulatory Commission (“FERC”)
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Utility and Review Board (“UARB”)
Peoples Gas System (“PGS”) – Gas Division of TEC	FPSC
New Mexico Gas Company, Inc. (“NMGC”)	New Mexico Public Regulation Commission (“NMPRC”)
SeaCoast Gas Transmission, LLC ("SeaCoast")	FPSC
Emera Brunswick Pipeline Company Limited (“Brunswick Pipeline”)	Canadian Energy Regulator ("CER")
Barbados Light & Power Company Limited (“BLPC”)	Fair Trading Commission, Barbados ("FTC")
Grand Bahama Power Company Limited (“GBPC”)	The Grand Bahama Port Authority (“GBPA”)
Equity Investments	
NSP Maritime Link Inc. (“NSPML”)	UARB
Labrador Island Link Limited Partnership (“LIL”)	Newfoundland and Labrador Board of Commissioners of Public Utilities ("NLPUB")
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline, LLC (“M&NP”)	CER and FERC
St. Lucia Electricity Services Limited (“Lucelec”)	National Utility Regulatory Commission (“NURC”)

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

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

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FORWARD-LOOKING INFORMATION

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations include without limitation: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; future dividend growth; timing and costs associated with certain capital investments; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats, such as the COVID-19 novel coronavirus ("COVID-19") pandemic; market energy sales prices; labour relations; and availability of labour and management resources.

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

INTRODUCTION AND STRATEGIC OVERVIEW

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

Emera's investment in rate-regulated businesses is concentrated in Florida and Nova Scotia. These service areas have generally experienced stable regulatory policies and economic conditions. Emera's portfolio of regulated utilities provides reliable earnings, cash flow and dividends. Earnings opportunities in regulated utilities are generally driven by the magnitude of net investment in the utility (known as "rate base"), and the amount of equity in the capital structure and the return on that equity ("ROE") as approved through regulation. Earnings are also affected by sales volumes and operating expenses.

Emera's capital investment plan is $8.4 billion over the 2022-to-2024 period (including a $240 million equity investment in the LIL in 2022), with an additional $1 billion of potential capital investments over the same period. This results in a forecasted rate base growth of approximately 7 per cent to 8 per cent through 2024. The capital investment plan continues to include significant investments across the portfolio in renewable and cleaner generation, reliability and integrity investments, infrastructure modernization and customer-focused technologies. Emera's capital investment plan is being funded primarily through internally generated cash flows and debt raised at the operating company level. Equity requirements in support of the Company's capital investment plan are expected to be funded through the issuance of preferred equity and the issuance of common equity through Emera's dividend reinvestment plan and at-the-market program ("ATM program"). Maintaining investment-grade credit ratings is a priority of management.

Emera has provided annual dividend growth guidance of four to five per cent through 2024. The Company targets a long-term dividend payout ratio of adjusted net income of 70 to 75 per cent and, while the payout ratio is likely to exceed that target through and beyond the forecast period, it is expected to return to that range over time. For further information on the non-GAAP measure "Dividend Payout Ratio of Adjusted Net Income", refer to the "Non-GAAP Financial Measures and Ratios" section.

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

Energy markets worldwide are facing significant change and Emera is well positioned to respond to shifting customer demands, digitization, decarbonization, complex regulatory environments and decentralized generation.

Customers are looking for more choice, better control, and enhanced reliability in a time where costs of decentralized generation and storage have become more competitive in some regions. Advancing technologies are transforming the way utilities interact with their customers and generate and transmit energy. In addition, climate change and extreme weather are shaping how utilities operate and how they invest in infrastructure. There is also an overall need to replace aging infrastructure and further enhance reliability. Emera sees opportunity in all 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, the ongoing construction of solar generation and modernization of the Big Bend Power Station at Tampa Electric, and planned NSPI investments to enable the retirement of its coal units and to achieve renewable energy targets. Emera's utilities are also investing in reliability projects and replacing aging infrastructure. All of these projects demonstrate Emera's strategy of safely delivering cleaner, reliable, and affordable energy for its customers.

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

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

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

Emera seeks to deliver on its Climate Commitment while maintaining its focus on investing in reliability and never losing sight of affordability for customers. Emera is also committed to identifying emerging technologies and continuing to work constructively with policymakers, regulators, partners, investors and customers to achieve these goals and realize its net-zero vision.

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

NON-GAAP FINANCIAL MEASURES AND RATIOS

Emera uses financial measures and ratios that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures and ratios by adjusting certain GAAP measures for specific items. Management believes excluding these items better distinguishes the ongoing operations of the business and allows investors to better understand and evaluate the business. These measures and ratios are discussed and reconciled below.

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

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

Management believes excluding from net income the effect of these MTM valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows and excludes these MTM adjustments for evaluation of performance and incentive compensation. The MTM adjustments are related to the following:

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

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

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

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

Emera calculates adjusted net income and adjusted earnings per common share – basic for the Canadian Electric Utilities, Other Electric Utilities and Other segments. Reconciliation to the nearest GAAP measure is included in each segment. Please refer to "Financial Highlights – Canadian Electric Utilities", "Financial Highlights – Other Electric Utilities" and "Financial Highlights – Other" sections. For further details on dividend payout ratio of adjusted net income, see the "Dividend Payout Ratio" section in Emera's Q4 2021 Annual MD&A.

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

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2022**	 2021
Net income attributable to common shareholders	**$ 362**	$ 273
MTM gain, after-tax (1)	**127**	30
NSPML unrecoverable costs (2)	**(7)**	-
Adjusted net income	**$ 242**	$ 243
Earnings per common share – basic	**$ 1.38**	$ 1.08
Adjusted earnings per common share – basic	**$ 0.92**	$ 0.96

(1) Net of income tax expense of $54 million for the three months ended March 31, 2022 (2021- $13 million expense).

(2) Emera accounts for NSPML as an equity investment and therefore the after-tax unrecoverable costs were recorded in "Income from equity investments" on Emera's Condensed Consolidated Statements of Income.

EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") and adjusted EBITDA are non-GAAP financial measures used by Emera. These financial measures are used by numerous investors and lenders to better understand cash flows and credit quality. EBITDA is useful to assess Emera's operating performance and indicates the Company's ability to service or incur debt, invest in capital and finance working capital requirements.

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

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

For the millions of Canadian dollars	Three months ended March 31 **2022**	 2021
Net income (1)	**$ 378**	$ 285
Interest expense, net	**156**	157
Income tax expense	**95**	56
Depreciation and amortization	**230**	226
EBITDA	**$ 859**	$ 724
MTM gain, excluding income tax	**181**	43
NSPML unrecoverable costs (2)	**(7)**	-
Adjusted EBITDA	**$ 685**	$ 681

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

(2) Emera accounts for NSPML as an equity investment and therefore the after-tax unrecoverable costs were recorded in "Income from equity investments" on Emera's Condensed Consolidated Statements of Income.

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Q1 Earnings

Earnings Impact of After-Tax MTM Gains

After-tax MTM gains increased $97 million to $127 million in Q1 2022 compared to $30 million in Q1 2021 due to a larger reversal of MTM losses in 2022, partially offset by higher amortization of gas transportation assets and changes in existing positions in 2022 at Emera Energy.

Consolidated Financial Highlights by Business Segment

For the millions of Canadian dollars	Three months ended March 31 **2022**	 2021
Adjusted Net Income		
Florida Electric Utility	**$ 112**	$ 83
Canadian Electric Utilities	**98**	88
Gas Utilities and Infrastructure	**77**	80
Other Electric Utilities	**1**	7
Other	**(46)**	(15)
Adjusted net income	**$ 242**	$ 243
MTM gain, after-tax	**127**	30
NSPML unrecoverable costs	**(7)**	-
Net income attributable to common shareholders	**$ 362**	$ 273

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

For the millions of Canadian dollars		Three months ended March 31
Adjusted net income – 2021	**$**	**243**
Operating Unit Performance		
Increased earnings at Tampa Electric due to higher base revenues as a result of base rate increases effective January 2022, returns related to capital cost recovery for early retired assets and favourable weather, partially offset by higher operating, maintenance and general expenses ("OM&G")		29
Increased earnings at NSPI driven by higher sales volumes, partially offset by increased OM&G primarily due to higher storm costs		9
Decreased earnings at Emera Energy Services ("EES") reflecting 2021's Winter Storm Uri, which resulted in incremental margin		(12)
Corporate		
Increased OM&G, "pre-tax", due to the timing of long-term incentive compensation and related hedges		(15)
Other Variances		(12)
Adjusted net income – 2022	**$**	**242**

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

For the millions of Canadian dollars		Three months ended March 31 **2022**		2021
Operating cash flow before changes in working capital	**$**	**482**	$	340
Change in working capital		**119**		(41)
Operating cash flow	**$**	**601**	$	299
Investing cash flow	**$**	**(513)**	$	(478)
Financing cash flow	**$**	**(98)**	$	196

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

As at millions of Canadian dollars		**March 31 2022**		December 31 2021
Total assets	**$**	**34,337**	$	34,244
Total long-term debt (including current portion)	**$**	**14,301**	$	14,658

Consolidated Income Statement Highlights

For the millions of Canadian dollars (except per share amounts)		Three months ended March 31 **2022**		2021		Variance
Operating revenues	**$**	**2,015**	$	1,612	$	403
Operating expenses		**1,436**		1,175		(261)
Income from operations	**$**	**579**	$	437	$	142
Income from equity investments		**27**		41		(14)
Other income, net		**23**		20		3
Interest expense, net		**156**		157		1
Income tax expense		**95**		56		(39)
Net income	**$**	**378**	$	285	$	93
Net income attributable to common shareholders	**$**	**362**	$	273	$	89
MTM gain, after-tax		**127**		30		97
NSPML unrecoverable costs		**(7)**		-		(7)
Adjusted net income	**$**	**242**	$	243	$	(1)
Earnings per common share – basic	**$**	**1.38**	$	1.08	$	0.30
Earnings per common share – diluted	**$**	**1.38**	$	1.08	$	0.30
Adjusted earnings per common share – basic	**$**	**0.92**	$	0.96	$	(0.04)
Dividends per common share declared	**$**	**0.6625**	$	0.6375	$	0.0250
Adjusted EBITDA	**$**	**685**	$	681	$	4

Operating Revenues

For Q1 2022, operating revenues increased $403 million compared to Q1 2021. Absent increased MTM gains of $142 million, operating revenues increased $262 million due to:

- $109 million increase in the Gas Utilities and Infrastructure segment due to higher purchased gas adjustment clause revenues at PGS and NMGC as a result of higher gas prices and higher base revenues at PGS due to customer growth;
- $80 million increase in the Florida Electric Utility segment due to higher base revenue reflecting new base rates effective January 2022, returns related to capital cost recovery for early retired assets, favourable weather and customer growth;
- $66 million increase in the Canadian Electric Utilities segment due to increased contribution from an industrial customer related to higher energy costs and increased sales volumes; and
- $25 million increase in the Other Electric Utilities segment due to higher fuel revenue at BLPC due to higher fuel prices.

These impacts were partially offset by an $18 million decrease in the Other segment due to decreased earnings at EES reflecting 2021's Winter Storm Uri, which resulted in incremental margin.

Operating Expenses

For Q1 2022, operating expenses increased $261 million compared to Q1 2021 due to:

- $107 million increase in the Gas Utilities and Infrastructure segment due to higher gas prices at PGS and NMGC;
- $65 million increase in the Canadian Electric Utilities segment due to an increase in fuel for generation and purchased power and increased OM&G;
- $39 million increase in the Florida Electric Utility segment due to higher OM&G and higher natural gas prices;
- $29 million increase in the Other Electric Utilities segment due to higher fuel prices at BLPC; and
- $15 million increase in the Other segment due to an increase in corporate OM&G reflecting the timing of long-term incentive compensation.

Income Tax Expense

The increase in income tax expense for Q1 2022 compared to Q1 2021 was primarily due to increased income before provision for income taxes.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For Q1 2022, the increase in net income attributable to common shareholders, compared to Q1 2021, was favourably impacted by the $97 million increase in after-tax MTM gains and unfavourably impacted by the $7 million in NSPML unrecoverable costs. Absent the MTM changes and NSPML unrecoverable costs, adjusted net income was consistent with Q1 2021. Increased earnings contributions from Tampa Electric and NSPI were offset by decreased earnings at EES and increased corporate OM&G.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic were higher for Q1 2022 compared to Q1 2021 due to increased earnings as discussed above, partially offset by the impact of the increase in weighted average shares outstanding. Adjusted earnings per common share – basic were lower for the first quarter due to the impact of the increase in weighted average shares outstanding.

Effect of Foreign Currency Translation

Emera operates internationally including in Canada, the United States and various Caribbean countries. As such, Emera 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 of foreign exchange in any period is driven by rate changes, the timing and percentage of earnings from foreign operations during the period, and the impact of entered foreign exchange cash flow hedges to manage foreign exchange earnings exposure.

Results of foreign operations are translated at the weighted average rate of exchange and assets and liabilities of foreign operations are translated at period end rates. The relevant CAD/USD exchange rates for 2022 and 2021 are as follows:

	Three months ended March 31		Year ended December 31
	2022	2021	2021
Weighted average CAD/USD	**$ 1.27**	$ 1.27	$ 1.26
Period end CAD/USD exchange rate	**$ 1.25**	$ 1.26	$ 1.27

The impact of the change in the foreign exchange rate on net income and adjusted net income in Q1 2022 was minimal.

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

For the millions of US dollars		Three months ended March 31 **2022**		2021
Florida Electric Utility	**$**	**88**	$	65
Gas Utilities and Infrastructure (1)		**58**		56
Other Electric Utilities		**1**		6
Other segment (2)		**(12)**		(2)
Total (3)	**$**	**135**	$	125

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's USD adjusted net income from EES, Bear Swamp, and interest expense on Emera Inc.'s USD denominated debt.
(3) Net of $103 million in after-tax MTM gains for the three months ended March 31, 2022 (2021- $23 million after-tax MTM gains).

BUSINESS OVERVIEW AND OUTLOOK

COVID-19 Pandemic

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

Florida Electric Utility

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

Tampa Electric anticipates earning within its ROE range in 2022. New base rates effective January 1, 2022 are expected to result in higher 2022 USD earnings than in 2021. Tampa Electric sales volumes are expected to be similar to 2021, which benefited from weather that was warmer than normal (a 20-year statistical degree day average). Tampa Electric expects customer growth rates in 2022 to be consistent with 2021, reflective of current economic growth in Florida.

The mid-course fuel adjustment requested by Tampa Electric on January 19, 2022, was approved on March 1, 2022. The rate increase, effective with the first billing cycle in April 2022, covered higher fuel and capacity costs of $169 million USD and will be spread over customer bills beginning April 1, 2022 through December 2022.

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

Canadian Electric Utilities

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

NSPI

NSPI anticipates earning within its allowed ROE range in 2022 and expects earnings to be consistent with 2021. Warmer than normal weather adversely affected NSPI's sales volumes in 2021. Assuming normal weather in 2022, NSPI expects sales volumes to be higher than 2021.

NSPI is currently operating under a three-year fuel stability plan which results in an average annual overall rate increase of 1.5 per cent to recover fuel costs for the period of 2020 through 2022. The 2022 rates include approximately $162 million related to the recovery of Maritime Link costs (discussed below in the "ENL, NSPML" section).

On January 27, 2022, NSPI filed a General Rate Application ("GRA") with the UARB, which was then amended on February 18, 2022. The GRA proposes a rate stability plan for 2022 through 2024 which includes average base rate increases of 2.8 per cent per year and average fuel rate increases pursuant to the Fuel Adjustment Mechanism ("FAM") of 0.8 per cent per year on August 1, 2022, January 1, 2023 and January 1, 2024. The proposed rates would result in annualized incremental revenue (base and fuel rates) increases of $52 million in 2022 ($21 million related to August 1, 2022 through December 31, 2022), $54 million in 2023 and $56 million in 2024. The hearing for this matter is scheduled to begin September 6, 2022 and a decision by the UARB is expected later in the year.

Energy from renewable sources has increased with Nalcor Energy's ("Nalcor") NS Block delivery obligations from the Muskrat Falls hydroelectric project ("Muskrat Falls") commencing August 15, 2021. Nalcor is obligated to provide NSPI with approximately 900 GWh of energy annually over 35 years. In addition, for the first five years of the NS Block, NSPI is also entitled to receive approximately 240 GWh of additional energy from the Supplemental Energy Block transmitted through the Maritime Link. Nalcor's final commissioning of the LIL has experienced delays. During these final stages of commissioning, there will be interruptions in supply, with any resultant delivery shortfalls being delivered at a date to be agreed to by the companies. Commencing in September 2022, NSPI has the option of purchasing additional market-priced energy from Nalcor through the Energy Access Agreement. Pursuant to the Energy Access Agreement, Nalcor is obligated to offer NSPI a minimum average of 1.2 TWh of energy annually. Nalcor is working towards final commissioning of the LIL in 2022.

In 2022, NSPI expects to invest $565 million (2021 – $388 million), including AFUDC, primarily in capital projects to support system reliability, renew hydroelectric infrastructure, and increase renewable energy.

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, please refer to the "Enterprise Risk and Risk Management" and "Business Overview and Outlook – Canadian Electric Utilities" sections respectively of Emera's 2021 annual MD&A. Recent developments related to provincial and federal environmental laws and regulations are outlined below.

Nova Scotia Cap-and-Trade Program Regulations:
In Q1 2022, NSPI received its 2022 granted emissions allowances under the Nova Scotia Cap-and-Trade Program Regulations. These allowances will be allocated within the initial four-year compliance period that ends in 2022. In addition to the granted allowances, NSPI is permitted to purchase up to five per cent of the credits available at provincial auctions or reserve credits, which are anticipated to be priced at a premium, from the provincial government.

Nova Scotia Renewable Energy Regulations:
The alternative compliance plan, under the provincially legislated Renewable Energy Regulations, requires NSPI to achieve 40 per cent of electric sales generated from renewable sources over the 2020 through 2022 period. With delivery of the NS Block commencing later than anticipated, as well as further interruptions in supply due to delays in the LIL, NSPI is not currently forecasting the ability to achieve the requirements of the alternative compliance plan. Throughout 2022, NSPI will continue to make best efforts toward achieving the standard and, as per the requirements of the Renewable Energy Regulations, NSPI intends to act 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

Equity earnings from NSPML and LIL are expected to be higher in 2022, compared to 2021. Both the NSPML and LIL investments are recorded as “Investments subject to significant influence” on Emera’s Condensed Consolidated Balance Sheets.

NSPML

Equity earnings from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. NSPML’s approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 30 per cent.

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

In February 2022, the UARB issued its decision and Board Order approving NSPML’s requested rate base of approximately $1.8 billion less approximately $9 million of costs ($7 million after-tax) that would not otherwise have been recoverable if incurred by NSPI. NSPML also received approval to collect $168 million (2021- $172 million) from NSPI for the recovery of Maritime Link costs in 2022. This is subject to a monthly holdback of up to $2 million from April to December 2022 contingent on receiving at least 90 per cent of NS Block deliveries, including Supplementary Energy deliveries, and the cost of replacement energy. NSPML will submit an application to the UARB in mid-2022 to recover Maritime Link costs for 2023.

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

LIL

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

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera’s current equity investment is $696 million, comprised of $410 million in equity contribution and $286 million of accumulated equity earnings. Emera’s total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $650 million after the Lower Churchill projects are completed.

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

Gas Utilities and Infrastructure

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

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

PGS anticipates earning within its allowed ROE range in 2022 and expects rate base and USD earnings to be higher than in 2021. PGS expects favourable customer growth in 2022 and sales volumes in 2022 are expected to increase at a level consistent with customer growth. The PGS rate case settlement, which was approved in November 2020, also provides the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. In Q1 2022, PGS reversed $5 million USD accumulated depreciation. The reversal of the remaining accumulated depreciation is expected to occur over the 2022 and 2023 periods.

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

On December 13, 2021, NMGC filed a rate case with the NMPRC for new rates to become effective January 2023. NMGC requested a $41 million USD increase in annual base revenues primarily as a result of increased operating costs and capital investments in pipelines and related infrastructure. A decision from the NMPRC is expected by the end of 2022.

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

In 2022, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $485 million USD (2021 - $407 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.

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

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

On January 14, 2022, the GBPA issued its decision on GBPC's rate application allowing for an increase in revenues of $3.5 million USD starting on April 1, 2022.

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

In 2022, capital investment in the Other Electric Utilities segment is expected to be $75 million USD (2021 – $88 million USD), primarily in more efficient and cleaner sources of generation, including renewables and battery storage.

Other

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

Business operations in the Other segment include Emera Energy and Emera Technologies LLC ("ETL"). Emera Energy consists of EES, a wholly owned physical energy marketing and trading business and an equity investment in a 50.0 per cent joint venture ownership of Bear Swamp, a 633 MW pumped storage hydroelectric facility in northwestern Massachusetts. ETL is a wholly owned technology company focused on finding ways to deliver renewable and resilient energy to customers.

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

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

The adjusted net loss from the Other segment is expected to be higher in 2022 due to higher Corporate OM&G which is primarily driven by the timing of the long-term incentive compensation and related hedges, EES returning to its normal earnings range, realized foreign exchange gains on cash flow hedges in 2021 and increased interest expense. The decrease 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 2022 (2021 – $1 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

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

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Inventory	**$ (100)**	Decreased due to lower natural gas volumes at Emera Energy and lower fuel inventory at NSPI.
Derivative instruments (current and long-term)	**167**	Increased due to higher commodity prices at NSPI and reversal of 2021 contracts at Emera Energy, partially offset by settlements at NSPI.
Regulatory assets (current and long-term)	**92**	Increased due to increased FAM deferrals at NSPI, higher cost recovery clauses at Tampa Electric and increased deferred income tax regulatory asset at NSPI. These were partially offset by the effect of a stronger CAD on the translation of Emera's foreign affiliates and recovery of the NMGC 2021 winter event gas cost.
Receivables and other assets (current and long-term)	**123**	Increased due to higher gas transportation assets at Emera Energy, the seasonal trends of NSPI's business and the required prepayment of income taxes and related interest at NSPI. These were partially offset by lower cash collateral and trade receivables due to lower volumes at Emera Energy.
Property, plant and equipment, net of accumulated depreciation and amortization	**(142)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates, and the reclassification of Seacoast's pipeline lateral as a sales type lease. These were partially offset by additions at Tampa Electric, PGS and NSPI.
Net investment in direct finance and sales type leases	**103**	Increased due to the commencement of the pipeline lease at Seacoast.
Goodwill	**(82)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**$ (238)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates and repayment of committed credit facilities at Emera and NSPI.
Accounts payable	**(64)**	Decreased due to timing of payments at Tampa Electric and PGS, and lower volumes at Emera Energy. These were partially offset by increased cash collateral position on derivative instruments at NSPI.
Deferred income tax liabilities, net of deferred income tax assets	**57**	Increased due to changes in derivative instruments at Emera Energy.
Derivative instruments (current and long-term)	**(63)**	Decreased due to reversal of 2021 contracts at Emera Energy, partially offset by new contracts in 2022 and changes in existing positions at Emera Energy.
Regulatory liabilities (current and long-term)	**127**	Increased due to deferrals related to derivative instruments at NSPI.
Other liabilities (current and long-term)	**180**	Increased due to emissions compliance accruals at NSPI, investment tax credits related to solar projects at Tampa Electric and timing of interest payments on long-term debt at Corporate.
Common stock	**123**	Increased due to Emera's ATM equity program and shares issued under the dividend reinvestment plan.
Accumulated other comprehensive income	**(130)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Retained earnings	**189**	Increased due to net income in excess of dividends paid.

OUTSTANDING STOCK DATA

Common stock

Issued and outstanding:	millions of shares	millions of Canadian dollars
Balance, December 31, 2020	251.43	$ 6,705
Issuance of common stock (1)	4.99	284
Issued for cash under Purchase Plans at market rate	4.32	239
Discount on shares purchased under Dividend Reinvestment Plan	-	(4)
Options exercised under senior management stock option plan	0.33	14
Employee Share Purchase Plan	-	4
Balance, December 31, 2021	261.07	$ 7,242
Issuance of common stock (2)	0.92	56
Issued for cash under Purchase Plans at market rate	1.13	66
Discount on shares purchased under Dividend Reinvestment Plan	-	(1)
Options exercised under senior management stock option plan	0.01	1
Employee Share Purchase Plan	-	1
Balance, March 31, 2022	**263.13**	**$ 7,365**

(1) In 2021, 4,987,123 common shares were issued under Emera's ATM program at an average price of $57.63 per share for gross proceeds of $287 million ($284 million net of after-tax issuance costs).

(2) In Q1 2022, 920,100 common shares were issued under Emera's ATM program at an average price of $60.81 per share for gross proceeds of $56 million ($56 million net of after-tax issuance costs). As at March 31, 2022, an aggregate gross sales limit of $401 million remained available for issuance under the ATM program.

As at May 10, 2022 the amount of issued and outstanding common shares was 263.7 million.

The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock, for the three months ended March 31, 2022 was 261.8 million (2021 – 253.5 million). 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.

FINANCIAL HIGHLIGHTS

Florida Electric Utility

All amounts are reported in USD, unless otherwise stated.

For the	Three months ended March 31	
millions of US dollars (except per share amounts)	**2022**	2021
Operating revenues – regulated electric	**$ 510**	$ 447
Regulated fuel for generation and purchased power	**$ 136**	$ 128
Contribution to consolidated net income	**$ 88**	$ 65
Contribution to consolidated net income – CAD	**$ 112**	$ 83
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.43**	$ 0.33
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.27**	$ 1.28

Net Income

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

For the millions of US dollars		Three months ended March 31
Contribution to consolidated net income – 2021	**$**	**65**
Increased operating revenues - see Operating Revenues - Regulated Electric below		63
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below		(8)
Increased OM&G due to timing of deferred clause recoveries, higher transmission and distribution, insurance and benefit costs		(19)
Increased income tax expense primarily due to increased income before provision for income taxes		(8)
Other		(5)
Contribution to consolidated net income – 2022	**$**	**88**

The impact of the change in the foreign exchange rate on earnings in Q1 2022 was minimal.

Operating Revenues – Regulated Electric

Electric revenues increased $63 million to $510 million in Q1 2022 compared to $447 million in Q1 2021 primarily due to new base rates effective January 2022, returns related to capital cost recovery for early retired assets, favourable weather and customer growth.

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

Q1 Electric Revenues in millions of US dollars		**2022**		2021
Residential	**$**	**270**	$	232
Commercial		**137**		126
Industrial		**37**		37
Other (1)		**66**		52
Total	**$**	**510**	$	447

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

Q1 Electric Sales Volumes in gigawatt hours ("GWh") (1)	**2022**	2021
Residential	**2,082**	2,053
Commercial	**1,375**	1,325
Industrial	**484**	474
Other	**532**	445
Total	**4,473**	4,297

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

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $8 million to $136 million in Q1 2022, compared to $128 million in Q1 2021, due to increased natural gas prices.

Q1 Production Volumes in GWh	**2022**	2021
Natural gas	**3,828**	3,407
Solar	**311**	286
Coal	**420**	406
Purchased power	**23**	340
Total	**4,582**	4,439

Average fuel cost per MWh increased to $30 per megawatt hour (“MWh”) in Q1 2022, compared to $29 in Q1 2021 due to increased natural gas prices.

Canadian Electric Utilities

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2022**	2021
Operating revenues – regulated electric	**$ 509**	$ 443
Regulated fuel for generation and purchased power (1)	**$ 303**	$ 212
Income from equity investments (2)	**$ 27**	$ 26
Contribution to consolidated adjusted net income	**$ 98**	$ 88
NSPML unrecoverable costs	**(7)**	-
Contribution to consolidated net income	**$ 91**	$ 88
Contribution to consolidated adjusted earnings per common share - basic	**$ 0.37**	$ 0.35
Contribution to consolidated earnings per common share - basic	**$ 0.35**	$ 0.35

(1) Regulated fuel for generation and purchased power includes NSPI's FAM and fixed cost deferrals on the Condensed Consolidated Income Statement, however it is excluded in the segment overview.
(2) Income from equity investments excludes $7 million in NSPML unrecoverable costs, after tax, for the three months ended March 31, 2022 (2021 - nil).

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

For the millions of Canadian dollars	Three months ended March 31 **2022**	2021
NSPI	**$ 71**	$ 62
Equity investment in NSPML	**13**	13
Equity investment in LIL	**14**	13
Contribution to consolidated adjusted net income	**$ 98**	$ 88

Net Income

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

For the millions of Canadian dollars	Three months ended March 31
Contribution to consolidated net income – 2021	**$ 88**
Increased operating revenues - see Operating Revenues - Regulated Electric below	66
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	(91)
Decreased FAM and fixed cost deferrals due to current period under-recovery of fuel costs	42
Increased OM&G primarily due to higher storm costs and increased costs for power generation	(13)
NSPML unrecoverable costs	(7)
Other	6
Contribution to consolidated net income – 2022	**$ 91**

NSPI

Operating Revenues – Regulated Electric

Operating revenues increased $66 million to $509 million in Q1 2022, compared to $443 million in Q1 2021. The increase was primarily due to increased contribution from an industrial customer related to increased energy costs, and increased residential, industrial and commercial class sales volumes.

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

Q1 Electric Revenues in millions of Canadian dollars	2022	2021
Residential	**$ 285**	$ 259
Commercial	**122**	114
Industrial	**88**	56
Other	**7**	7
Total	**$ 502**	$ 436

Q1 Electric Sales Volumes in GWh	2022	2021
Residential	**1,687**	1,549
Commercial	**864**	822
Industrial	**601**	572
Other	**39**	43
Total	**3,191**	2,986

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $91 million to $303 million in Q1 2022 compared to $212 million in Q1 2021, due to increased provision recognized as part of the Nova Scotia Cap-and-Trade Program and increased sales volumes, partially offset by changes in generation mix.

The provision for the Nova Scotia Cap-and-Trade program was $73 million for the three months ended March 31, 2022 (2021 – nil). This non-cash accrual represents the estimated future cost of acquiring emissions credits for the 2019 through 2022 compliance period. These costs are estimated based on forecast emissions for the compliance period and are sensitive to changes to forecasts of energy received from Muskrat Falls for the remainder of 2022 and the actual emissions profile.

Q1 Production Volumes in GWh	2022	2021
Coal	**1,317**	1,654
Natural Gas	**322**	313
Petcoke	**239**	206
Oil	**207**	51
Purchased power – other	**160**	105
Total non-renewables	**2,245**	2,329
Purchased power	**705**	546
Wind and hydro	**431**	305
Biomass	**48**	37
Total renewables	**1,184**	888
Total production volumes	**3,429**	3,217

Average fuel cost per MWh increased in Q1 2022 to $88 per MWh, compared to $66 per MWH in Q1 2021, primarily due to increased provision recognized as part of the Nova Scotia Cap-and-Trade Program, partially offset by a favourable change in generation mix.

NSPI's FAM regulatory asset balance increased $64 million to $209 million at March 31, 2022 from $145 million at December 31, 2021 due to an under-recovery of current period fuel costs.

Gas Utilities and Infrastructure

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended March 31 2022	2021
Operating revenues – regulated gas (1)	**$ 398**	$ 312
Operating revenues – non-regulated	**3**	3
Total operating revenue	**$ 401**	$ 315
Regulated cost of natural gas	**$ 202**	$ 124
Income from equity investments	**$ 4**	$ 4
Contribution to consolidated net income	**$ 61**	$ 63
Contribution to consolidated net income – CAD	**$ 77**	$ 80
Contribution to consolidated earnings per common share – basic - CAD	**$ 0.29**	$ 0.32
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.27**	$ 1.27

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2021 – $11 million), however, it is excluded from the gas revenues analysis below.

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

For the millions of US dollars	Three months ended March 31 2022	2021
PGS	**$ 30**	$ 27
NMGC	**19**	24
Other	**12**	12
Contribution to consolidated net income	**$ 61**	$ 63

Net Income

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

For the millions of US dollars	Three months ended March 31
Contribution to consolidated net income – 2021	**$ 63**
Increased gas operating revenues - see Operating Revenues - Regulated Gas below	86
Increased cost of natural gas sold - see Regulated Cost of Natural Gas below	(78)
Increased OM&G due to higher labour and benefit costs at NMGC and PGS	(7)
Other	(3)
Contribution to consolidated net income – 2022	**$ 61**

The impact of the change in the foreign exchange rate on earnings in Q1 2022 was minimal.

Operating Revenues – Regulated Gas

Operating revenues increased $86 million to $398 million in Q1 2022, compared to $312 million in Q1 2021 due to higher purchased gas adjustment clause revenues at PGS and NMGC as a result of higher gas prices and higher base revenues at PGS due to customer growth.

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

Q1 Gas Revenues in millions of US dollars		**2022**		2021
Residential	**$**	**219**	$	172
Commercial		**108**		90
Industrial (1)		**14**		12
Other (2)		**46**		27
Total (3)	**$**	**387**	$	301

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $11 million of finance income from Brunswick Pipeline (2021 – $11 million).

Q1 Gas Volumes in millions of Therms	**2022**	2021
Residential	**191**	188
Commercial	**252**	242
Industrial	**344**	367
Other	**46**	47
Total	**833**	844

Regulated Cost of Natural Gas

Regulated cost of natural gas increased $78 million to $202 million in Q1 2022, compared to $124 million in Q1 2021, due to higher gas prices at NMGC and PGS.

Gas sales by type are summarized in the following table:

Q1 Gas Volumes by Type in millions of Therms	**2022**	2021
System supply	**282**	266
Transportation	**551**	578
Total	**833**	844

Other Electric Utilities

All amounts are reported in USD, unless otherwise stated.

For the	Three months ended March 31			
millions of US dollars (except per share amounts)		**2022**		2021
Operating revenues – regulated electric	**$**	**94**	$	74
Regulated fuel for generation and purchased power	**$**	**50**	$	33
Contribution to consolidated adjusted net income	**$**	**1**	$	6
Contribution to consolidated adjusted net income - CAD	**$**	**1**	$	7
Equity securities MTM loss	**$**	**(2)**	$	-
Contribution to consolidated net income (loss)	**$**	**(1)**	$	6
Contribution to consolidated net income (loss) – CAD	**$**	**(1)**	$	7
Contribution to consolidated adjusted earnings per common share – basic – CAD	**$**	**-**	$	0.03
Contribution to consolidated earnings per common share – basic – CAD	**$**	**-**	$	0.03
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.27**	$	1.26

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

For the millions of US dollars	Three months ended March 31 **2022**	2021
GBPC	**$ 2**	$ 5
BLPC	**2**	2
Other	**(3)**	(1)
Contribution to consolidated adjusted net income	**$ 1**	$ 6

Excluding the change in MTM, Other Electric Utilities' CAD contribution to consolidated net income decreased by $6 million to $1 million in Q1 2022, compared to $7 million in Q1 2021. The decrease was due to the recognition of Hurricane Dorian insurance proceeds at GBPC in Q1 2021.

The impact of the change in the foreign exchange rate on earnings in Q1 2022 was minimal.

Operating Revenues – Regulated Electric

Operating revenues increased $20 million to $94 million in Q1 2022 compared to $74 million in Q1 2021, due to higher fuel revenue at BLPC due to higher fuel prices.

Electric sales volumes were 307 GWh in Q1 2022 compared to 289 GWh in Q1 2021.

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $17 million to $50 million in Q1 2022, compared to $33 million in Q1 2021 due to higher fuel prices at BLPC.

Other

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2022**	2021
Marketing and trading margin (1) (2)	**$ 49**	$ 67
Other non-regulated operating revenue	**7**	8
Total operating revenues – non-regulated	**$ 56**	$ 75
Income from equity investments	**$ 4**	$ 7
Contribution to consolidated adjusted net income (loss)	**$ (46)**	$ (15)
MTM gain, after-tax (3)	**129**	30
Contribution to consolidated net income	**$ 83**	$ 15
Contribution to consolidated adjusted earnings per common share – basic	**$ (0.18)**	$ (0.06)
Contribution to consolidated earnings per common share – basic	**$ 0.32**	$ 0.06

(1) Marketing and trading margin represents EES's purchases and sales of natural gas and electricity, pipeline and storage capacity costs and energy asset management services' revenues.

(2) Marketing and trading margin excludes a pre-tax MTM gain of $190 million for the three months ended March 31, 2022 (2021 - $38 million gain).

(3) Net of income tax expense of $54 million for the three months ended March 31, 2022 (2021 - $13 million expense).

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

For the millions of Canadian dollars	Three months ended March 31 **2022**	 2021
Emera Energy	**$ 27**	$ 43
Corporate – see breakdown of adjusted contribution below	**(67)**	(54)
Emera Technologies	**(5)**	(3)
Other	**(1)**	(1)
Contribution to consolidated adjusted net income (loss)	**$ (46)**	$ (15)

Net Income

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

For the millions of Canadian dollars	Three months ended March 31
Contribution to consolidated net income – 2021	**$ 15**
Decreased marketing and trading margin - see Emera Energy below	(18)
Increased OM&G primarily due to the timing of long-term incentive compensation and related hedges	(15)
Increased income tax recovery primarily due to increased losses before provision for income taxes	12
Increased preferred stock dividends due to the issuance of preferred shares in Q2 and Q3 2021	(5)
Increased MTM gain, net of tax, primarily due to a larger reversal of MTM losses in 2022, partially offset by higher amortization of gas transportation assets and changes in existing positions in 2022 at Emera Energy	99
Other	(5)
Contribution to consolidated net income – 2022	**$ 83**

Emera Energy

Excluding the impact of increased MTM gains, marketing and trading margin decreased $18 million to $49 million in Q1 2022 compared to $67 million in Q1 2021 reflecting 2021's Winter Storm Uri, which resulted in incremental margin.

Corporate

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

For the millions of Canadian dollars	Three months ended March 31 **2022**	 2021
Operating expenses (1)	**$ 15**	$ -
Interest expense	**65**	68
Income tax recovery	**(21)**	(18)
Preferred dividends	**16**	11
Other	**(8)**	(7)
Adjusted contribution to consolidated net income (loss)	**$ (67)**	$ (54)

(1) Operating expenses include OM&G and depreciation. In 2021, OM&G and depreciation were offset by changes 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.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash from its various regulated and non-regulated energy investments. Utility customer bases are diversified by both sales volumes and revenues among customer classes. Emera's non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company's ability to generate cash include general economic downturns in markets served by Emera, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets and changes in environmental legislation. Emera's subsidiaries are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment, and maintain their credit metrics.

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

Emera's future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera has a $8.4 billion capital investment plan over the 2022-to-2024 period (including a $240 million equity investment in the LIL in 2022) and the potential for additional capital investments of $1 billion over the same period. This plan includes significant rate base investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. Capital investments at the regulated utilities are subject to regulatory approval.

Emera plans to use cash from operations and debt raised at the utilities to support normal operations, repayment of existing debt, and capital requirements. Debt raised at certain of the Company's utilities is subject to applicable regulatory approvals. Equity requirements in support of the Company's capital investment plan are expected to be funded through the issuance of preferred equity and the issuance of common equity through Emera's dividend reinvestment plan and ATM program.

Emera has credit facilities with varying maturities that cumulatively provide $3.8 billion of credit, with approximately $1.5 billion undrawn and available at March 31, 2022. The Company was holding a cash balance of $404 million at March 31, 2022. For further discussion, refer to the "Debt Management" section below. Refer to notes 18 and 19 in the condensed consolidated interim financial statements for additional information regarding the credit facilities.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the three months ended March 31, 2022 and 2021 include:

millions of Canadian dollars	**2022**	2021	Change
Cash, cash equivalents, and restricted cash, beginning of period	**$ 417**	$ 254	$ 163
Provided by (used in):			
Operating cash flow before change in working capital	**482**	340	142
Change in working capital	**119**	(41)	160
Operating activities	**$ 601**	$ 299	$ 302
Investing activities	**(513)**	(478)	(35)
Financing activities	**(98)**	196	(294)
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**(3)**	(3)	-
Cash, cash equivalents, and restricted cash, end of period	**$ 404**	$ 268	$ 136

Cash Flow from Operating Activities

Net cash provided by operating activities increased $302 million to $601 million for the three months ended March 31, 2022, compared to $299 million for the same period in 2021.

Cash from operations before changes in working capital increased $142 million. This increase was primarily due to the 2021 deferral of gas costs at NMGC resulting from the extreme cold weather event and increased revenues at Tampa Electric and NSPI. This was partially offset by under-recovery of clause-related costs primarily due to higher natural gas prices at Tampa Electric and PGS.

Changes in working capital increased operating cash flows by $160 million due to favourable changes in cash collateral positions at NSPI and Emera Energy, timing of accounts payable payments at NSPI and lower inventory at Emera Energy. These were partially offset by unfavourable changes in accounts receivable and the required prepayment of income taxes and related interest at NSPI.

Cash Flow from Investing Activities

Net cash used in investing activities increased $35 million to $513 million for the three months ended March 31, 2022, compared to $478 million for the same period in 2021. This increase was due to higher capital investment in 2022.

Capital expenditures for the three months ended March 31, 2022, including AFUDC, were $533 million compared to $491 million for the same period in 2021. Details of the 2022 capital investment by segment are shown below:

- $292 million - Florida Electric Utility (2021 – $244 million);
- $100 million - Canadian Electric Utilities (2021 – $73 million);
- $125 million - Gas Utilities and Infrastructure (2021 – $146 million);
- $15 million - Other Electric Utilities (2021 – $26 million); and
- $1 million - Other (2021 – $2 million).

Cash Flow from Financing Activities

Net cash used in financing activities increased $294 million to $98 million for the three months ended March 31, 2022, compared to cash provided by financing activities of $196 million for the same period in 2021. The increase was due to net proceeds from the issuance of long-term debt at Tampa Electric, PGS and NMGC in 2021 and higher net repayments of committed credit facilities at Emera and NSPI. This was partially offset by lower net repayments of short-term debt at Tampa Electric and PGS.

Contractual Obligations

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

millions of Canadian dollars	2022	2023	2024	2025	2026	Thereafter	Total
Long-term debt principal	$ 442	$ 587	$ 813	$ 500	$ 3,228	$ 8,847	$ 14,417
Interest payment obligations (1)	539	585	574	554	473	6,520	9,245
Transportation (2)	438	464	377	321	295	2,588	4,483
Purchased power (3)	194	228	242	236	228	2,309	3,437
Fuel, gas supply and storage	758	136	54	48	31	-	1,027
Capital projects	369	98	4	1	-	-	472
Asset retirement obligations	7	7	2	2	1	391	410
Long-term service agreements (4)	52	57	56	40	33	92	330
Pension and post-retirement obligations (5)	23	37	33	32	32	169	326
Equity investment commitments (6)	240	-	-	-	-	-	240
Leases and other (7)	11	15	14	12	5	115	172
Demand side management	36	1	1	1	-	-	39
Long-term payable	4	5	-	-	-	-	9
	$ 3,113	$ 2,220	$ 2,170	$ 1,747	$ 4,326	$ 21,031	$ 34,607

(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 March 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 $137 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) Maintenance of certain generating equipment, services related to a generation facility and wind operating agreements, outsourced management of computer and communication infrastructure and vegetation management.
(5) 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.
(6) Emera has a commitment to make equity contributions to the LIL upon its commissioning.
(7) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. In February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion and the approval to collect $168 million from NSPI for the recovery of Maritime Link costs in 2022. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Once LIL has been commissioned, the commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties relating to the Maritime Link and LIL.

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

Debt Management

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

millions of dollars	Maturity	Credit Facilities	Utilized	Undrawn and Available
Emera – Unsecured committed revolving credit facility	June 2026	$ 900	$ 385	$ 515
TEC (in USD) – Unsecured committed revolving credit facility (1)	December 2026	800	314	486
NSPI – Unsecured committed revolving credit facility	December 2026	600	323	277
TEC (in USD) – Unsecured non-revolving facility (2)	December 2022	500	500	-
Emera – Unsecured non-revolving facility	December 2022	400	400	-
TECO Finance (in USD) – Unsecured committed revolving credit facility	December 2026	400	345	55
NMGC (in USD) – Unsecured revolving credit facility	December 2026	125	2	123
NMGC (in USD) – Unsecured non-revolving facility	September 2022	80	80	-
Other (in USD) – Unsecured committed revolving credit facilities	Various	20	11	9

(1) This facility is available for use by Tampa Electric and PGS. At March 31, 2022, $247 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 March 31, 2022, $400 million USD was used by Tampa Electric and $100 million USD was used by PGS.

Emera and its subsidiaries have certain financial and other covenants associated with their debt and credit facilities. Covenants are tested regularly, and the Company is in compliance with covenant requirements as at March 31, 2022.

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

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.

Guarantees and Letters of Credit

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

The Company has standby letters of credit and surety bonds in the amount of $119 million USD (December 31, 2021 - $148 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually, as required.

Emera Inc. has issued a guarantee of $66 million USD relating to outstanding notes of ECI. This guarantee will automatically terminate on the date upon which the obligations have been repaid in full.

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

TRANSACTIONS WITH RELATED PARTIES

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

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

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Condensed Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $34 million for the three months ended March 31, 2022 (2021 - $28 million). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments. For further details, refer to the "Business Overview and Outlook - Canadian Electric Utilities - ENL" and "Contractual Obligations" sections.

- Natural gas transportation capacity purchases from M&NP are reported in the Condensed Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $4 million for the three months ended March 31, 2022 (2021 - $7 million).

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

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

There have been no material changes in Emera's risk management profile and practices from those disclosed in the Company's 2021 annual MD&A.

Hedging Impact Recognized in Net Income

The Company recognized gains related to the effective portion of hedging relationships under the following category:

For the	Three months ended March 31	
millions of Canadian dollars	**2022**	2021
Interest expense, net	**$ 1**	$ -
Effective net gains	**$ 1**	$ -

Regulatory Items Recognized on the Balance Sheets

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

As at	**March 31**	December 31
millions of Canadian dollars	**2022**	2021
Derivative instrument assets (current and other assets)	**$ 380**	$ 237
Regulatory assets (current and other assets)	**11**	23
Derivative instrument liabilities (current and long-term liabilities)	**(14)**	(20)
Regulatory liabilities (current and long-term liabilities)	**(389)**	(241)
Net liability	**$ (12)**	$ (1)

Regulatory Impact Recognized in Net Income

The Company recognized the following net gains related to derivatives receiving regulatory deferral as follows:

For the millions of Canadian dollars	Three months ended March 31 **2022**	2021
Regulated fuel for generation and purchased power (1)	**$ 64**	$ 3
Net gains	**$ 64**	$ 3

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

HFT Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**March 31 2022**	December 31 2021
Derivative instrument assets (current and other assets)	**$ 80**	$ 53
Derivative instrument liabilities (current and long-term liabilities)	**(605)**	(662)
Net derivative instrument liability	**$ (525)**	$ (609)

HFT Items Recognized in Net Income

The Company has recognized the following realized and unrealized gains with respect to HFT derivatives in net income:

For the millions of Canadian dollars	Three months ended March 31 **2022**	2021
Operating revenues – non-regulated	**$ 190**	$ 133
Non-regulated fuel for generation and purchased power	**-**	1
Net gains	**$ 190**	$ 134

Other Derivatives Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**March 31 2022**	December 31 2021
Derivative instrument assets (current and other assets)	**$ 8**	$ 11
Derivative instrument liabilities (current and other liabilities)	**-**	-
Net derivative instrument assets	**$ 8**	$ 11

Other Derivatives Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended March 31 **2022**	2021
OM&G	**$ (4)**	$ 5
Other income, net	**1**	1
Total (losses) gains	**$ (3)**	$ 6

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures (“DC&P”) and internal control over financial reporting (“ICFR”), as defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings. The Company’s internal control framework is based on the criteria published in the Internal Control - Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design of the Company’s DC&P and ICFR as at March 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 quarter ended March 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 condensed consolidated interim financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, allowance for credit losses, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations, and valuation of financial instruments. Management evaluates the Company’s estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. There were no material changes in the nature of the Company’s critical accounting estimates from those disclosed in Emera’s 2021 annual MD&A.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Future Accounting Pronouncements

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

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of Canadian dollars (except per share amounts)		**Q1 2022**	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020
Operating revenues	**$**	**2,015**	$ 1,868	$ 1,148	$ 1,137	$ 1,612	$ 1,537	$ 1,163	$ 1,169
Net income (loss) attributable to common shareholders	**$**	**362**	$ 324	$ (70)	$ (17)	$ 273	$ 273	$ 84	$ 58
Adjusted net income	**$**	**242**	$ 168	$ 175	$ 137	$ 243	$ 188	$ 166	$ 118
Earnings (loss) per common share - basic	**$**	**1.38**	$ 1.24	$ (0.27)	$ (0.07)	$ 1.08	$ 1.09	$ 0.34	$ 0.24
Earnings (loss) per common share - diluted	**$**	**1.38**	$ 1.20	$ (0.27)	$ (0.07)	$ 1.08	$ 1.08	$ 0.34	$ 0.23
Adjusted earnings per common share - basic	**$**	**0.92**	$ 0.64	$ 0.68	$ 0.54	$ 0.96	$ 0.75	$ 0.67	$ 0.48

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