
Emera
2021
ANNUAL REPORT

2021 Financial Highlights

Data is as of December 31, 2021, unless otherwise indicated.

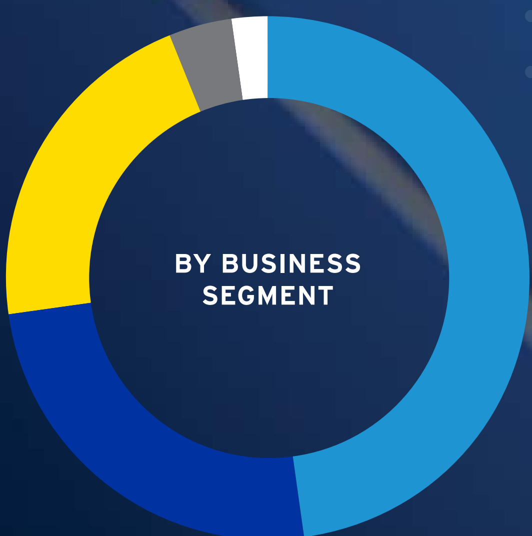
11.5% annualized total shareholder return over the last 10 years

5.5% annualized dividend growth since 2000

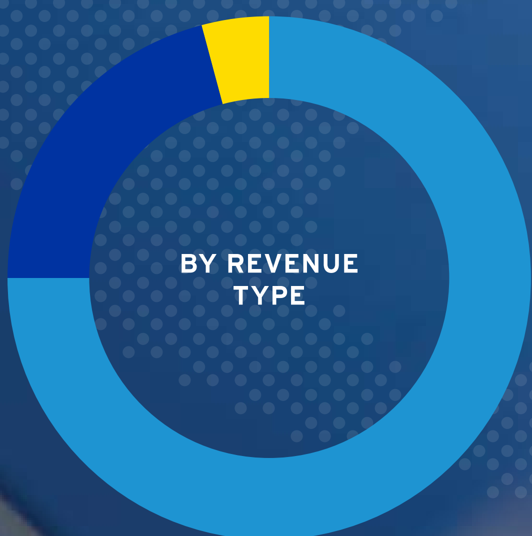
95%+ of adjusted net income* from regulated investments

2021 Adjusted Net Income*

Excluding corporate net loss



- Florida electric (48%)
- Canadian electric (25%)
- Gas utilities and infrastructure (21%)
- Other (4%)
- Other electric (2%)



- Regulated electric (75%)
- Regulated gas (21%)
- Unregulated (4%)

* Based on 2021 adjusted net income attributable to common shareholders ("adjusted net income"), excluding corporate net loss of $231 million. Adjusted net income is a non-GAAP measure which does not have a standardized meaning under US GAAP. Refer to "Non-GAAP Financial Measures" in the MD&A for a reconciliation to the nearest GAAP measure.

Emera at a Glance

Data is as of December 31, 2021, unless otherwise indicated.

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electric and natural gas utilities in Canada, the US and the Caribbean

2.5M

customers

$5.8B

revenue

8%

growth in adjusted net income* since 2017

7,100+

employees

$34B

total assets

$5.3B+

of capital plan through 2024 committed to cleaner energy and reliability projects

42%

of Board of Director nominees for 2022 are women, including Chair

1.06 OSHA**

injury rate – 8% improvement over 5-year average of 1.15

** Occupational Safety & Health Administration

98%

shareholder support for 2021 Say on Pay vote

* Based on 2021 adjusted net income excluding corporate net loss of $231 million. Adjusted net income is a non-GAAP measure which does not have a standardized meaning under US GAAP. Refer to "Non-GAAP Financial Measures" in the MD&A for a reconciliation to the nearest GAAP measure.

Our Strategy

ESG is core to our strategy and our culture. It drives our growth and inspires innovation. We're investing in cleaner sources of energy, in transmission assets to deliver that energy, and in enhancing reliability — all while never losing sight of affordability for customers.

Expert Teams

We're a team of experts leading the way to a cleaner energy focus as we work toward our 2050 Net-Zero Vision.

Delivering for Our Customers

Every day, we're safely delivering cleaner, affordable and reliable energy for our customers.

Driving Growth and Reinvestment

Delivering for our customers drives predictable returns and steady growth for our investors, enabling us to reinvest in our teams, companies and communities.

Delivering on Our Climate Commitment

Decarbonization has been a central part of our strategy since 2005. As we work toward our vision to achieve net-zero CO_2 emissions by 2050, we're making progress on our clear, future-focused goals[1] along the way.

2021 PROGRESS

40%
reduction in CO_2 emissions from 2005[2]

1,365 MW
installed renewable capacity[3]

65%
reduction in use of coal from 2005 levels[4]

Our Climate Commitment

2023 GOAL

80%
reduction in use of coal

2025 GOAL

55%
reduction of CO_2 emissions

2040 GOAL

80%
reduction of CO_2 emissions and **last coal unit retired** no later than 2040

2050 VISION

Net-zero
CO_2 emissions

1 Our Climate Commitment goals are compared to 2005 levels.
2 Undergoing third party verification.
3 Total installed capacity is 9,784 MW.
4 Reduction in GWh generated from coal.

Why Invest in Emera

With our proven strategy and portfolio of high-quality regulated utilities, Emera is well positioned to continue to deliver for our customers while also providing our shareholders with long-term growth in earnings, cash flow and dividends.

VISIBLE GROWTH PLAN

$8.4B to $9.4B

capital investment plan[1] through 2024

7% to 8%

forecasted rate base growth through 2024

60%

of adjusted net income,[2] excluding corporate net loss, comes from Florida, and **67%** of CapEx plan focused in Florida – one of the fastest growing US states

STRONG, ESG-DRIVEN STRATEGY

60%+

of capital plan to 2024 committed to decarbonization and reliability

$13M

invested in our communities in 2021

Recognized for excellence in governance

Strong Board and management oversight of ESG

SUSTAINABLE DIVIDEND GROWTH

4% to 5%

dividend growth target through 2024

4.2%

dividend yield[3]

CONSTRUCTIVE REGULATORY ENVIRONMENTS

Highly rated

regulatory environments

89%

of adjusted net income[2], excluding corporate net loss, derived from our four core regulated utilities

1 Emera's capital investment plan includes $240 million equity investment in 2022.
2 Based on 2021 adjusted net income, excluding corporate net loss of $231 million. Adjusted net income is a non-GAAP measure which does not have a standardized meaning under US GAAP. Refer to "Non-GAAP Financial Measures" in the MD&A for more information and a reconciliation to the nearest GAAP measure.
3 As of December 31, 2021. Our share price on this date was $63.22.

Jackie Sheppard
Chair, Emera Inc. Board of Directors

Scott Balfour
President and Chief Executive Officer, Emera Inc.

Letter from the Chair and the CEO

Fellow shareholders,

Throughout 2021, our team continued to execute on our proven strategy of safely delivering cleaner, affordable and reliable energy to our customers. We made progress on our Climate Commitment, we continued to invest in reliability and cost-effective solutions for customers, and we stayed focused on keeping each other safe.

FINANCIAL RESULTS

Our record of providing predictable earnings growth and long-term shareholder value continues. Since 2017, we've delivered eight per cent average annual growth in adjusted net income. We raised our dividend by four per cent in 2021, solidifying more than 15 years of sustainable dividend growth.

We reported $723 million in annual adjusted net income[1] in 2021 — our highest to date. We delivered adjusted earnings per share[1] (EPS) for the year of $2.81, an increase of five per cent compared to 2020.

1 Adjusted net income and adjusted EPS are non-GAAP measures which do not have a standardized meaning under US GAAP. Refer to the "Non-GAAP Financial Measures" section of the MD&A for a reconciliation to the nearest GAAP measure.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE (ESG)

ESG has been core to our strategy and culture for more than 15 years. More recently, we've seen unprecedented focus on ESG by global policymakers, investors and other stakeholders who are seeking additional transparency on how companies like ours are responding to important issues like climate change, social justice and diversity, equity and inclusion. We've established a strong sustainability function at Emera that's focused on strengthening ESG governance while driving deep integration and disciplined disclosure.

We believe that strong governance is the foundation that supports our ESG efforts going forward. We've established a Sustainability Management Committee (SMC), chaired by our CEO, as well as the Risk and Sustainability Committee of the Board to oversee the management of our ESG priorities and risks. We've developed strong tracking tools and have fully integrated key ESG factors into our established risk management protocols.

In addition to other key disclosure frameworks, we're guided by the Task Force on Climate-related Financial Disclosures (TCFD) as we look to enhance our climate disclosures and provide further transparency related to our energy transition plans and climate adaptation work. Our full Sustainability Report will be released in June.

CLIMATE COMMITMENT

Early last year, we announced our Climate Commitment — a set of clear goals to reduce emissions and our vision to achieve net-zero CO_2 emissions by 2050. As a result of our investments in cleaner, more reliable energy, and the work of our dedicated teams, we achieved a 40 per cent reduction in CO_2 emissions across Emera in 2021, compared to 2005 levels, and we are on track to achieve our goal of a 55 per cent reduction by 2025.

DIVERSITY, EQUITY AND INCLUSION (DEI)

We value the many benefits diversity brings to Emera, and we continue to promote and foster DEI across the business. In addition to providing ongoing support for employee-led DEI networks, in 2021 we created a company-wide DEI Council to drive common focus and share best practices. We also gathered employee self-identification data to assess our baseline and gaps, and we requested and received input on DEI from our team through our employee engagement survey. We continue to hold employee celebrations and educational events throughout the year.

We're also supporting DEI in our communities through our $5 million Emera DEI Fund. In the first year of the Fund, we contributed over $1.9 million to organizations working to advance DEI in our communities.

“Across Emera, we have the right people executing on our proven strategy, ensuring we’re well positioned to continue to provide predictable, sustainable growth in earnings and shareholder value.”

STRATEGY IN ACTION

In 2021, we made rate base investments of over $2.4 billion focused on decarbonization and reliability. Our updated capital plan through 2024 is $8.4–$9.4 billion – that’s a billion dollars higher than our previous forecast, and we see opportunities to extend this growth well beyond 2024.

- Hydroelectricity from Muskrat Falls began flowing across the Maritime Link to Nova Scotia in 2021. Access to this significant source of clean energy will be a major contributor to achieving our company-wide Climate Commitment goals, and will support Nova Scotia Power in meeting its target of 80 per cent renewable energy by 2030.
  - The Maritime Link was an extraordinary project that Emera delivered on time and on budget. Early this year, we received final approval from our regulator on the $1.8 billion project costs. This is a significant achievement for the business and a testament to our transparent and disciplined approach to large capital projects.
- At Tampa Electric, we announced our plan for building a cleaner energy future that aligns with our Emera-wide Climate Commitment. As part of this plan, the team is advancing installation of another 600 MW of solar generation, adding to the 650 MW already in operation. Once complete, solar will account for roughly 19 per cent of total generation capacity at Tampa Electric, up from about one per cent in 2016.
- We completed the first phase of the Big Bend modernization project, further reducing our use of coal at Tampa Electric. This complex first phase was completed on time and on budget. The next phase, which will include waste-heat recovery to improve efficiency, is on track for completion by the end of 2022.
- We continued to invest in new technologies and innovation to support our climate goals.
  - As part of the Smart Grid Nova Scotia project, we launched the province’s first grid-connected community solar garden. The project is also testing the benefits of battery storage systems, electric vehicle smart chargers and bidirectional chargers.
  - Emera Technologies’ BlockEnergy solution technology delivers high levels of reliable, renewable energy by integrating rooftop solar, energy storage and smart controls. BlockEnergy is now part of two residential pilot projects, one in Florida and one in Maryland.
  - The team at New Mexico Gas continues to test hydrogen blending as a way to reduce methane emissions. Current testing could lead to a full-scale pilot later this year.
- At Barbados Light & Power, the team completed construction of the Clean Energy Bridge – a new plant that will be a reliable source of energy for customers as we transition to a cleaner energy future on the island.
- At our two largest utilities, Nova Scotia Power and Tampa Electric, we invested approximately $250 million in 2021 to enhance reliability and grid resilience. As a result of investments like this over the last several years, both utilities have significantly reduced the frequency of outages.
- We also achieved important regulatory outcomes across Emera in 2021 that enable continued progress in these key areas in the years ahead. We reached rate settlements at all our US affiliates, and the regulator in Grand Bahama also issued its decision approving our GBPC rate application while the regulator in Nova Scotia approved the final cost application for the Maritime Link.

SAFETY PERFORMANCE

Safety is our top priority across Emera. Our efforts have resulted in an improved OSHA injury rate over the last five years; however, two contractor fatalities in 2021 remind us that we need to stay focused on safety at all times. Over the past year, we've reinforced our contractor safety management, ensuring all contractors working with us understand our safety expectations and meet our standards. We also developed an Emera-wide Serious Injury & Fatality Prevention Program that's being implemented across the business with an emphasis on managing high-risk work.

Over the last year, our teams have remained proactive and adapted quickly in response to the evolving COVID-19 pandemic. We implemented new safety procedures and protocols as needed to keep employees, customers and communities safe while also sustaining critical operations.

BOARD OF DIRECTORS

John Ramil, the former CEO of TECO Energy, is stepping down from our Board of Directors this year. John joined our Board when Emera acquired TECO in 2016. Since then, we've greatly benefitted from the significant business and utility sector experience gained from his 40-year career with TECO, along with his deep knowledge and understanding of his community. John, on behalf of the Board and management team, we thank you for your invaluable contribution and wish you well. You will be missed.

We would also like to welcome two new Directors — Paula Gold-Williams and Ian Robertson — who joined our Board earlier this year. Paula is the former President and CEO of CPS Energy and brings deep operational expertise and extensive experience in strong stakeholder management and in driving clean energy innovation. Ian is a founder and former CEO of Algonquin Power & Utilities Corp. He is an accomplished driver of corporate growth and experienced in the development and operation of renewable energy projects. Paula and Ian, welcome to the Emera Board.

THANK YOU

Across Emera, we have the right people executing on our proven strategy, ensuring we're well positioned to continue to provide predictable, sustainable growth in earnings and shareholder value.

To the Board of Directors and the entire Emera team, thank you for your unwavering commitment to delivering for customers, communities and investors.

To our valued shareholders, thank you for your ongoing confidence.

Jackie Sheppard
Chair, Emera Inc.
Board of Directors

Scott Balfour
President and Chief
Executive Officer, Emera Inc.

Financial Review

Management's Discussion & Analysis

As at February 14, 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 fourth quarter of 2021 relative to the same quarter in 2020; for the full year of 2021 relative to 2020 and selected financial information for 2019; and its financial position as at December 31, 2021 relative to December 31, 2020. Throughout this discussion, "Emera Incorporated", "Emera" and "Company" refer to Emera Incorporated and all of its consolidated subsidiaries and investments. The Company's activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Other Electric Utilities, Gas Utilities and Infrastructure, and Other.

This discussion and analysis should be read in conjunction with the Emera Incorporated annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 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 December 31, 2021, Emera's rate-regulated subsidiaries and investments include:

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

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

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

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

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. 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" 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

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

Adjusted Net Income 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, impacts in 2020 of the gain on sale of Emera Maine, and impairment charges on certain other assets.

The MTM adjustments are a result of the following:

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

Management believes excluding from net income the effect of these MTM valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows and ongoing operations of the business, and allows investors to better understand and evaluate the business. Management and the Board of Directors exclude these MTM adjustments for evaluation of performance and incentive compensation. For further detail on MTM adjustments, refer to the "Consolidated Financial Review", "Financial Highlights – Other Electric Utilities", and "Financial Highlights – Other" 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. For further details, refer to the "Significant Items Affecting Earnings" and "Financial Highlights – Other" sections. While the gain on sale has been excluded from adjusted earnings, earnings for the Other Electric Utilities segment includes earnings from Emera Maine up to the date of its sale on March 24, 2020.

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 attributable to common shareholders, 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 and adjusted earnings per common share – basic for the Other Electric Utilities and Other segments. Reconciliation to the nearest GAAP measure is included in each segment. Please refer to "Financial Highlights – Other Electric Utilities" and "Financial Highlights – Other" sections.

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

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31 2021	 2020	 2021	Year ended December 31 2020	 2019
Net income attributable to common shareholders	**$ 324**	$ 273	**$ 510**	$ 938	$ 663
Gain on sale, net of tax and transaction costs (1)	**–**	–	**–**	309	–
Impairment charges, net of tax (2)	**–**	–	**–**	(26)	(34)
After-tax MTM gains (losses) (3)	**156**	85	**(213)**	(10)	76
Adjusted net income attributable to common shareholders	**$ 168**	$ 188	**$ 723**	$ 665	$ 621
Earnings per common share – basic	**$ 1.24**	$ 1.09	**$ 1.98**	$ 3.78	$ 2.76
Adjusted earnings per common share – basic	**$ 0.64**	$ 0.75	**$ 2.81**	$ 2.68	$ 2.59

(1) Net of income tax expense of $276 million for the year ended December 31, 2020
(2) Net of income tax expense of $1 million for the year ended December 31, 2020 (2019 – nil)
(3) Net of income tax expense of $63 million for the three months ended December 31, 2021 (2020 – $33 million expense) and $86 million recovery for the year ended December 31, 2021 (2020 – $8 million recovery) (2019 – $31 million expense)

EBITDA and Adjusted EBITDA

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

Adjusted EBITDA is a non-GAAP financial measure used by Emera. Similar to adjusted net income calculations described above, this measure represents EBITDA absent the income effect of Emera's MTM adjustments, the gain on sale of Emera Maine and impairment charges.

The Company's EBITDA and Adjusted EBITDA may not be comparable to the EBITDA measures of other companies but, in management's view, appropriately reflect Emera's specific operating performance. These measures are not intended to replace "Net income attributable to common shareholders" which, as determined in accordance with GAAP, is an indicator of operating performance.

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

For the millions of Canadian dollars	Three months ended December 31 2021	 2020	 2021	Year ended December 31 2020	 2019
Net income (1)	**$ 338**	$ 284	**$ 561**	$ 984	$ 710
Interest expense, net	**151**	159	**611**	679	738
Income tax expense (recovery)	**85**	57	**(6)**	341	61
Depreciation and amortization	**227**	217	**902**	881	903
EBITDA	**$ 801**	$ 717	**$ 2,068**	$ 2,885	$ 2,412
Gain on sale, net of transaction costs (excluding income tax)	**–**	–	**–**	585	–
Impairment charges, excluding income tax	**–**	–	**–**	(25)	(34)
MTM gains (losses), excluding income tax	**219**	118	**(299)**	(18)	107
Adjusted EBITDA	**$ 582**	$ 599	**$ 2,367**	$ 2,343	$ 2,339

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

Consolidated Financial Review

SIGNIFICANT ITEMS AFFECTING EARNINGS

Earnings Impact of After-Tax MTM Gains and Losses

After-tax MTM gains increased $71 million to $156 million in Q4 2021, compared to $85 million in Q4 2020, primarily due to settlements and changes in existing positions at Emera Energy. These were partially offset by higher amortization on gas transportation assets in Q4 2021 at Emera Energy and the reversal of 2020 foreign exchange gains on cash flow hedges. For the year ended December 31, 2021, after-tax MTM losses increased $203 million to $213 million compared to $10 million for the same period in 2020 due to changes in existing positions at Emera Energy and the reversal of 2020 foreign exchange gains on cash flow hedges.

2020 TECO Guatemala Holdings ("TGH") International Arbitration and Award

On November 24, 2020, a payment was made by the Republic of Guatemala in satisfaction of an award issued by the International Centre for the Settlement of Investment Disputes tribunal in 2013. The payment of $49 million ($36 million after tax or $0.15 per common share), net of legal costs was related to a dispute over an investment in a Guatemala local distribution company and was recognized in "Other Income" on the Consolidated Statements of Income. For further detail, refer to note 27 in the consolidated financial statements.

2020 Gain on Sale and Impairment Charges

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

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

CONSOLIDATED FINANCIAL HIGHLIGHTS BY BUSINESS SEGMENT

For the millions of Canadian dollars **Adjusted net income**	Three months ended December 31 **2021**	 2020	Year ended December 31 **2021**	 2020	 2019
Florida Electric Utility	**$ 85**	$ 101	**$ 462**	$ 501	$ 419
Canadian Electric Utilities	**67**	57	**241**	221	229
Other Electric Utilities	**5**	8	**20**	33	76
Gas Utilities and Infrastructure	**55**	45	**198**	162	183
Other	**(44)**	(23)	**(198)**	(252)	(286)
Adjusted net income attributable to common shareholders	**$ 168**	$ 188	**$ 723**	$ 665	$ 621
Gain on sale, net of tax and transaction costs	**–**	–	**–**	309	–
Impairment charges, net of tax	**–**	–	**–**	(26)	(34)
After-tax MTM gains (losses)	**156**	85	**(213)**	(10)	76
Net income attributable to common shareholders	**$ 324**	$ 273	**$ 510**	$ 938	$ 663

The following table highlights the significant changes in adjusted net income attributable to common shareholders from 2020 to 2021:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2020	**$ 188**	**$ 665**
Operating Unit Performance		
Increased earnings at Emera Energy Services ("EES") due to favourable market conditions	9	37
Increased earnings at PGS due to higher base revenues as a result of a base rate increase on January 1, 2021 and customer growth	10	36
Increased earnings at NSPI due to increased sales volumes quarter-over-quarter. Year-over-year increased due to higher operating revenues, lower interest on the Fuel Adjustment Mechanism ("FAM") regulatory deferral and decreased income tax expense	7	15
Decreased earnings at Tampa Electric due to higher depreciation and amortization expense, reflecting increased capital investment and a 2020 regulatory settlement, the impact of a stronger CAD and lower base revenue due to weather, partially offset by higher allowance for funds used during construction ("AFUDC")	(16)	(39)
Decreased earnings due to the sale of Emera Maine in Q1 2020	–	(6)
Tax Related		
Revaluation of Corporate, NSPI and Emera Energy net deferred income tax assets and liabilities in Q1 2020 due to the reduction in the Nova Scotia provincial corporate income tax rate	–	14
Recognition of corporate income tax recovery in Q1 2020 previously deferred as a regulatory liability in 2018 at BLPC	–	(10)
Corporate		
Decreased interest expense, pre-tax, due to the impact of a stronger CAD and lower interest rates. Year-over-year also due to repayment of corporate debt	6	35
Realized gain on hedges entered into to hedge foreign exchange earnings exposure	2	19
TGH award, net of tax and legal costs in Q4 2020. Refer to the "Significant Items Affecting Earnings" section	(36)	(36)
Other Variances	(2)	(7)
Adjusted net income – 2021	**$ 168**	**$ 723**

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

For the millions of Canadian dollars	**2021**	2020	Year ended December 31 2019
Operating cash flow before changes in working capital	**$ 1,337**	$ 1,420	$ 1,598
Change in working capital	**(152)**	217	(73)
Operating cash flow	**$ 1,185**	$ 1,637	$ 1,525
Investing cash flow	**$ (2,332)**	$ (1,224)	$ (1,617)
Financing cash flow	**$ 1,311**	$ (372)	$ 14

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

As at millions of Canadian dollars	**2021**	2020	December 31 2019
Total assets	**$ 34,244**	$ 31,234	$ 31,842
Total long-term debt (including current portion)	**$ 14,658**	$ 13,721	$ 14,180

CONSOLIDATED INCOME STATEMENT HIGHLIGHTS

For the millions of Canadian dollars (except per share amounts)	**2021**	Three months ended December 31 2020	Variance	**2021**	Year ended December 31 2020	Variance	Year ended December 31 2019
Operating revenues	**$ 1,868**	$ 1,537	$ 331	**$ 5,765**	$ 5,506	$ 259	$ 6,111
Operating expenses	**1,352**	1,148	(204)	**4,835**	4,359	(476)	4,768
Income from operations	**$ 516**	$ 389	$ 127	**$ 930**	$ 1,147	$ (217)	$ 1,343
Income from equity investments	**32**	36	(4)	**143**	149	(6)	154
Other income, net	**26**	75	(49)	**93**	708	(615)	12
Interest expense, net	**151**	159	8	**611**	679	68	738
Income tax expense (recovery)	**85**	57	(28)	**(6)**	341	347	61
Net income	**$ 338**	$ 284	$ 54	**$ 561**	$ 984	$ (423)	$ 710
Net income attributable to common shareholders	**$ 324**	$ 273	$ 51	**$ 510**	$ 938	$ (428)	$ 663
Gain on sale, net of tax and transaction costs	**-**	-	-	**-**	309	(309)	-
Impairment charges, net of tax	**-**	-	-	**-**	(26)	26	(34)
After-tax MTM gains (losses)	**156**	85	71	**(213)**	(10)	(203)	76
Adjusted net income attributable to common shareholders	**$ 168**	$ 188	$ (20)	**$ 723**	$ 665	$ 58	$ 621
Earnings per common share - basic	**$ 1.24**	$ 1.09	$ 0.15	**$ 1.98**	$ 3.78	$ (1.80)	$ 2.76
Earnings per common share - diluted	**$ 1.20**	$ 1.08	$ 0.12	**$ 1.98**	$ 3.78	$ (1.80)	$ 2.76
Adjusted earnings per common share - basic	**$ 0.64**	$ 0.75	$ (0.11)	**$ 2.81**	$ 2.68	$ 0.13	$ 2.59
Dividends per common share declared	**$ 0.6625**	$ 0.6375	$ 0.0250	**$ 2.5750**	$ 2.4750	$ 0.1000	$ 2.3750
Adjusted EBITDA	**$ 582**	$ 599	$ (17)	**$ 2,367**	$ 2,343	$ 24	$ 2,339

Operating Revenues

For the fourth quarter of 2021, operating revenues increased $331 million compared to the fourth quarter in 2020. Absent increased MTM gains of $112 million, operating revenues increased $219 million due to:

- $97 million increase in the Florida Electric Utility segment due to higher fuel recovery clause revenues as a result of higher fuel costs, partially offset by lower base revenue due to less favourable weather than in Q4 2020 and the impact of a stronger CAD;
- $82 million increase in the Gas Utilities and Infrastructure segment due to base rate increases at PGS and NMGC effective January 1, 2021, customer growth at PGS, and higher purchased gas adjustment clause revenues at PGS and NMGC as a result of higher gas prices. These increases were partially offset by the impact of a stronger CAD;
- $21 million increase in the Other Electric Utilities segment due to higher fuel revenue at BLPC due to higher fuel prices; and
- $17 million increase in Other segment due to higher marketing and trading margin at EES, primarily driven by favourable market conditions.

For the year ended December 31, 2021, operating revenues increased $259 million compared to 2020. Absent increased MTM losses of $241 million, operating revenues increased by $500 million due to:

- $244 million increase in the Florida Electric Utility segment due to higher fuel recovery clause revenues as a result of higher fuel costs, partially offset by lower base revenue due to less favourable weather than in the prior year and the impact of a stronger CAD;
- $222 million increase in the Gas Utilities and Infrastructure segment due to base rate increases at PGS and NMGC effective January 1, 2021, customer growth at PGS, and higher purchased gas adjustment clause revenues at PGS and NMGC as a result of higher gas prices. These increases were partially offset by the impact of a stronger CAD; and
- $64 million increase in Other segment due to higher marketing and trading margin at EES, primarily driven by favourable market conditions.

These impacts were partially offset by:

- $29 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020.

Operating Expenses

For the fourth quarter of 2021, operating expenses increased $204 million compared to the fourth quarter of 2020. Operating expenses increased due to:

- $121 million increase in the Florida Electric Utility segment due to higher natural gas prices, partially offset by the impact of a stronger CAD;
- $73 million increase in the Gas Utilities and Infrastructure segment due to higher gas prices at PGS and NMGC, partially offset by the impact of a stronger CAD; and
- $28 million increase in the Other Electric Utilities segment due to higher fuel prices at BLPC.

For the year ended December 31, 2021, operating expenses increased $476 million compared to 2020. Absent the 2020 impairment charges of $26 million, operating expenses increased $502 million due to:

- $331 million increase in the Florida Electric Utility segment due to higher natural gas prices, partially offset by the impact of a stronger CAD;
- $187 million increase in the Gas Utilities and Infrastructure segment due to higher gas prices at PGS and NMGC, partially offset by the impact of a stronger CAD; and
- $42 million increase in the Other Electric segment due to higher fuel prices at BLPC.

These impacts were partially offset by:

- $48 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020.

Other Income, Net

Other income, net decreased for Q4 2021 and year ended December 31, 2021, compared to the same periods in 2020, primarily due to the TGH award in Q4 2020. For the year ended December 31, 2021, the decrease was also primarily due to the pre-tax gain on sale of Emera Maine in Q1 2020.

Interest Expense, Net

Interest expense, net was lower for Q4 2021 and year ended December 31, 2021, compared to the same periods in 2020, due to the impact of a stronger CAD and lower interest rates. For the year ended December 31, 2021, the decrease was also due to the repayment of long-term corporate debt.

Income Tax (Recovery) Expense

The increase in income tax expense for Q4 2021, compared to the same period in 2020, was primarily due to increased income before provision for income taxes. The decrease in income tax expense in 2021, compared to 2020, was primarily due to the gain on sale of Emera Maine.

Net Income and Adjusted Net Income

For the fourth quarter of 2021, the decrease in net income attributable to common shareholders, compared to the same period in 2020, was favourably impacted by the $71 million increase in after-tax MTM gains primarily related to Emera Energy. Absent the favourable MTM changes, adjusted net income decreased $20 million. The decrease was primarily due to the TGH award in Q4 2020 and lower earnings at Tampa Electric, partially offset by higher earnings contribution from PGS, EES, and NSPI.

For the year ended December 31, 2021, net income attributable to common shareholders, compared to the same period in 2020, was unfavourably impacted by the $309 million after-tax gain on sale of Emera Maine in 2020, unfavourably impacted by the $203 million increase in after-tax MTM losses primarily related to Emera Energy, and favourably impacted by the $26 million after-tax impairment charge in 2020. Absent the net gain on sale of Emera Maine in 2020, the unfavourable MTM changes and the 2020 impairment charges, adjusted net income increased $58 million. The increase was primarily due to higher earnings contribution from EES, PGS and NSPI, lower corporate interest expense, realized gains on foreign exchange hedges and the 2020 revaluation of deferred taxes due to a reduction in the Nova Scotia corporate income tax rate. The increase was partially offset by the TGH award in Q4 2020, the impact of a stronger CAD, and the 2020 recognition of a corporate income tax recovery previously deferred as a regulatory liability in 2018 at BLPC.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic were higher for Q4 2021, compared to Q4 2020 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 Q4 2021 compared to Q4 2020 due to decreased earnings as discussed above, and the impact of the increase in weighted average shares outstanding.

Earnings per common share – basic for the year ended December 31, 2021 decreased compared to 2020 due to the decreased earnings as discussed above, and the impact of the increase in weighted average shares outstanding. Adjusted earnings per common share were higher for the year ended December 31, 2021, compared to 2020, due to increased adjusted earnings as discussed above, partially offset by the impact of the increase in weighted average shares outstanding.

Effect of Foreign Currency Translation

Emera operates internationally including in Canada, the US and various Caribbean countries. As such, the Company generates revenues and incurs expenses denominated in local currencies which are translated into 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 of earnings from foreign operations during the period, the percentage of earnings from foreign operations in 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 2021 and 2020 are as follows:

	Three months ended December 31		Year ended December 31	
	2021	2020	**2021**	2020
Weighted average CAD/USD	**$ 1.26**	$ 1.30	**$ 1.26**	$ 1.34
Period end CAD/USD exchange rate	**$ 1.27**	$ 1.27	**$ 1.27**	$ 1.27

Strengthening of the CAD decreased net income by $10 million and decreased adjusted net income by $1 million in Q4 2021, compared to Q4 2020. The strengthening of the CAD decreased net income by $17 million and adjusted net income by $28 million for the year ended December 31, 2021, compared to 2020.

Consistent with the Company's risk management policies, Emera partially manages currency risks through matching US denominated debt to finance its US operations and uses foreign currency derivative instruments to hedge specific transactions and earnings exposure. Emera does not utilize derivative financial instruments for foreign currency trading or speculative purposes.

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

For the millions of US dollars	Three months ended December 31		Year ended December 31	
	2021	2020	**2021**	2020
Florida Electric Utility	**$ 67**	$ 76	**$ 369**	$ 372
Other Electric Utilities	**4**	5	**16**	24
Gas Utilities and Infrastructure (1)	**37**	30	**130**	97
Other segment (2)	**(20)**	5	**(98)**	(102)
Total (3)	**$ 88**	$ 116	**$ 417**	$ 391

(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 $122 million in after-tax MTM gain for the three months ended December 31, 2021 (2020 – $62 million after-tax MTM gain) and after-tax MTM loss of $164 million for the year ended December 31, 2021 (2020 – $11 million after-tax MTM loss, and $212 million gain on sale of Emera Maine, net of tax and transaction costs).

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 continues to have varying effects on the service territories in which Emera operates, on a consolidated basis, COVID-19 did not have a material financial impact on net income in 2021. Capital project delays and supply chain disruptions have also been minimal. The Company continues to monitor developments, economic conditions and recommendations by local and national public health authorities related to COVID-19 and is adjusting operational requirements as needed.

The extent of the future impact of COVID-19 on the Company's financial results and business operations cannot be predicted at this time but is not expected to have a material financial impact in 2022. Future impacts will depend on a variety of factors, including the duration and severity of the pandemic, timing and effectiveness of vaccinations, further government actions and future economic activity and energy usage.

Potential future impacts of COVID-19 on the business may include the following:

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

The Company currently expects to continue to have adequate liquidity given its cash position, existing bank facilities, and access to capital, but will continue to monitor the impact of COVID-19 on future cash flows. For further detail, refer to the "Liquidity and Capital Resources" section.

Refer to the outlook sections by segment below, for affiliate specific impacts, if applicable.

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 $10.7 billion USD of assets and approximately 810,600 customers at December 31, 2021. Tampa Electric owns 5,919 MW of generating capacity, of which 77 per cent is natural gas-fired, 12 per cent is solar and 11 per cent is coal. Tampa Electric owns 2,165 kilometres of transmission facilities and 19,530 kilometres of distribution facilities.

Beginning in 2022, Tampa Electric's approved regulated ROE range is 9.00 per cent to 11.00 per cent, based on an allowed equity capital structure of 54 per cent (2021 – 9.25 per cent to 11.25 per cent based on an allowed equity capital structure of 54 per cent). An ROE of 9.95 per cent (2021 – 10.25 per cent) will be used for the calculation of the return on investments for clauses. See below for further detail.

Tampa Electric anticipates earning within its ROE range in 2022. New base rates effective January 1, 2022 will 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 expected economic growth in Florida.

On January 19, 2022, Tampa Electric requested a mid-course adjustment to its fuel and capacity charges to recover an additional $169 million USD, effective with April 2022 customer bills, due to an increase in fuel commodity and capacity costs. The FPSC is expected to issue its decision in March 2022.

On August 6, 2021, Tampa Electric filed with the FPSC a joint motion for approval of a settlement agreement (the "Settlement Agreement") by Tampa Electric and the intervenors in relation to its rate case filed with the FPSC in April 2021. The Settlement Agreement provides for a projected increase of $191 million USD in rates annually, effective with January 2022 bills. This increase will consist of $123 million USD in base rate charges and $68 million USD to recover the costs of retiring assets including, Big Bend coal generation assets Units 1 through 3 and meter assets. The Settlement Agreement further includes two subsequent year adjustments of $90 million USD and $21 million USD, effective January 2023 and January 2024, respectively related to the recovery of future investments in the Big Bend Modernization project and solar generation. The allowed equity in the capital structure will continue to be 54 per cent from investor sources of capital. The Settlement Agreement includes an allowed regulated ROE range of 9.0 per cent to 11.0 per cent with a 9.95 per cent midpoint. It also provides for a 25 basis point increase in the allowed ROE range and mid-point, and $10 million USD of additional revenue, if U.S. Treasury Bond yields exceed a specific threshold set on the date the FPSC votes to approve the agreement. Under the agreement, base rates will not further change from January 1, 2022 through December 31, 2024, unless Tampa Electric's earned ROE were to fall below the bottom of the range during that time. The Settlement Agreement contains a provision whereby Tampa Electric agrees to quantify the future impact of a change in tax rates on net operating income through a reduction or increase in base revenues within 180 days of when such tax change becomes law or its effective date. The Settlement Agreement further creates a mechanism to recover the costs of retiring coal generation units and meter assets over a period of 15 years which survives the term of that agreement. The Settlement Agreement sets new depreciation and dismantlement rates effective January 1, 2022 and contains the provisions that Tampa Electric will not have to file another depreciation study during the term of the agreement but will file a new depreciation study no more than one year, nor less than 90 days, before the filing of its next general base rate proceeding. Tampa Electric agreed not to hedge natural gas through the period ending on December 31, 2024. On October 21, 2021, the FPSC approved the Settlement Agreement and the final order, reflecting such approval, was issued in November 2021.

In 2022, capital investment in the Florida Electric Utility segment is expected to be $1.1 billion USD (2021 – $1.2 billion USD), including AFUDC. Capital projects include continuation of the modernization of the Big Bend Power Station, 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 $6.1 billion of assets and approximately 536,000 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 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. Due to continued rate base growth, 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. These rates include 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. The GRA proposes a rate stability plan for 2022 through 2024 which includes average base rate increases of 2.9 per cent per year and average fuel rate increases pursuant to the 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. A decision by the UARB is expected later this year.

NSPI is subject to environmental laws and regulations set by both the Government of Canada and the Province of Nova Scotia. NSPI continues to work with both levels of government to comply with these laws and regulations to maximize efficiency of emission control measures and minimize customer cost. NSPI anticipates that costs prudently incurred to achieve legislated reductions will be recoverable under NSPI's regulatory framework.

Over the past several years, the requirement to reduce Nova Scotia's reliance on higher carbon and GHG emitting sources of energy has resulted in NSPI making significant investments in renewable energy sources, including energy from the Maritime Link, and purchasing renewable energy from IPPs.

In Q1 2021, NSPI received its 2021 granted emissions allowances under the Nova Scotia Cap-and-Trade Program Regulations. These 2021 allowances will be used in 2021 or 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. Any remaining allowance shortfall requires the purchase of reserve credits directly from the provincial government. Reserve credits are anticipated to be priced at a premium to provincial auction pricing. Compliance is forecast to be achieved through granted emissions allowances, reduced emissions partly due to delivery of energy from Muskrat Falls, and credit purchases under the Cap-and-Trade Program, including reserve credits. NSPI anticipates that any prudently incurred costs required to comply with the Government of Canada's laws and regulations, and the Nova Scotia Cap-and-Trade Program Regulations, will be recoverable under NSPI's regulatory framework.

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 will 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. As Nalcor is in the final stages of commissioning the LIL, there will be periodic commissioning related 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 forecasting it will achieve final commissioning of the Lower Churchill projects (including Muskrat Falls and LIL) in the first half of 2022.

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 in 2020, as permitted by the legislation. The alternative compliance plan requires NSPI to supply customers with at least 40 per cent of energy generated from renewable sources over the 2020 through 2022 period. With full delivery of the NS Block having only recently commenced, NSPI's ability to achieve 40 per cent of total sales from renewable sources over the 2020 through 2022 period may be at risk. If NSPI is found not to have acted in a duly diligent manner, it could be subject to a maximum penalty of $10 million. As 2022 progresses, NSPI will monitor its progress toward achieving the 40 per cent standard and, as per the requirements of the Renewable Energy Regulations, NSPI intends to act in a duly diligent manner.

There have been several recent environmental developments at both the federal and provincial levels, as described further below. These developments are consistent with NSPI's decarbonization strategy and will facilitate an accelerated transition to cleaner energy. NSPI is engaging with the federal and provincial governments, customers and stakeholders to work towards achieving these requirements, goals and targets with a focus on customer affordability.

On November 5, 2021, the provincial government enacted Bill 57, "Environmental Goals and Climate Change Reduction Act," which signals the provincial government's intent to implement several climate change related goals and greenhouse gas reduction targets, many of which overlap with and replace provisions of pre-existing acts. The legislation also introduces a goal to phase out coal-fired electricity generation in Nova Scotia by 2030. Subsequent provincial regulations will be required to detail how these goals and targets will be achieved.

On August 5, 2021, the federal government issued an update to the Pan-Canadian Framework on Clean Growth and Climate Change under the "Greenhouse Gas Pollution Pricing Act". This update (the "Federal Benchmark") applies to the 2023 through 2030 period and puts in place the legal mechanism for increasing the carbon tax in Canada by $15 per tonne annually and reaching $170 per tonne by 2030. It also outlines the minimum compliance criteria for recognizing systems like the Nova Scotia Cap-and-Trade Program to be considered equivalent to the Federal Benchmark.

On July 9, 2021, the provincial government amended the Renewable Electricity Regulations, mandating that 80 per cent of electric sales be generated from renewable sources by 2030.

On June 29, 2021, the federal government enacted Bill C-12 "Canadian Net-Zero Emissions Accountability Act" with the objective of attaining net-zero emissions by 2050.

In 2022, NSPI expects to invest $530 million (2021 – $388 million), including AFUDC, primarily in capital projects to support system reliability, renew hydroelectric infrastructure, and increase renewable energy.

ENL

Total 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 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 with Nalcor forecasting it will achieve final commissioning in the first half of 2022. 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 at a date to be agreed to by the companies.

NSPML received UARB approval to collect up to $172 million (2020 – $145 million) from NSPI for the recovery of costs associated with the Maritime Link in 2021. This was subject to a holdback of up to $10 million that was dependent upon the timing of commencement of the NS Block. On January 18, 2022, the UARB directed NSPI to pay to NSPML approximately $10 million of the 2021 holdback. NSPML has deferred collection and recognition of $23 million in depreciation expense. Approximately $162 million is included in NSPI rates in 2022.

On August 9, 2021, NSPML filed a final capital cost application with the UARB, seeking approval to recover capital costs associated with the Maritime Link and approval of NSPML's 2022 assessment. In December 2021, NSPML obtained an interim decision from the UARB approving interim rates beginning January 1, 2022, until receipt of the UARB's decision on the application. On February 9, 2022, the UARB issued its decision relating to the Maritime Link Project, approving NSPML's requested rate base of approximately $1.8 billion less costs that would not otherwise have been recoverable if incurred by NSPI. The UARB also approved approximately $168 million of NSPML revenue requirement in 2022 subject to a holdback of $2 million per month beginning April 1, 2022 and thereafter to the end of the year. This holdback is to be used to fund any replacement energy costs incurred by NSPI due to a 10 per cent or greater shortfall in contracted NS Block deliveries each month and will otherwise be released to NSPML. NSPML is required to provide the UARB with a compliance filing by February 16, 2022 which will confirm the impacts of this decision including the amount of the unrecoverable items which are not expected to exceed $10 million (pre-tax).

In 2022, NSPML expects to invest approximately $5 million (2021 – $6 million) in capital.

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 the first half of 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 $682 million, comprised of $410 million in equity contribution and $272 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 the first half of 2022, and until that point Emera will continue to record AFUDC earnings.

OTHER ELECTRIC UTILITIES

Other Electric Utilities includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities. ECI's regulated utilities include vertically integrated regulated electric utilities of BLPC on the island of Barbados, GBPC on Grand Bahama Island, a 51.9 per cent interest in Domlec on the island of Dominica and a 19.5 per cent interest in Lucelec on the island of St. Lucia which is accounted for on the equity basis.

On March 24, 2020, Emera completed the sale of Emera Maine which is included in the Other Electric Utilities segment for Q1 2020.

BLPC

With $489 million USD of assets and approximately 132,000 customers, BLPC owns 266 MW of generating capacity, of which 96 per cent is oil-fired and four per cent is solar. The utility has an additional 12 MW of capacity from rental units. BLPC owns approximately 188 kilometres of transmission facilities and 3,800 kilometres of distribution facilities. BLPC's approved regulated return on rate base is 10.0 per cent.

GBPC

With $349 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. Restoration of the generating units damaged by Hurricane Dorian was completed in 2021. GBPC's approved regulatory return on rate base for 2022 is 8.23 per cent (2021 – 8.37 per cent). See below for further details.

Domlec

Domlec serves approximately 35,700 customers. Domlec owns 26.7 MW of generating capacity, of which 75 per cent is oil-fired and 25 per cent is hydro. Domlec owns approximately 475 kilometres of transmission facilities and 709 kilometres of distribution facilities. Domlec's approved regulated return on rate base is 15.0 per cent.

Other Electric Utilities Outlook

Other Electric Utilities' 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.

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. Following a general election called late in 2021 for January 19, 2022, the new licenses are expected to take effect in 2022 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 currently assessing the full impact of the new licenses on its business and working towards the successful implementation of the licenses.

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. A decision is expected from the FTC in the second half of 2022.

On January 14, 2022, the GBPA issued its decision on GBPC's application for rate review that was filed with the GBPA on September 23, 2021. The decision, which becomes 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.

In 2022, capital investment in the Other Electric Utilities segment is expected to be $100 million USD (2021 – $88 million USD), primarily in more efficient and cleaner sources of generation, including renewables and battery storage.

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 $2.2 billion USD of assets and approximately 445,000 customers, the PGS system includes 23,150 kilometres of natural gas mains and 13,100 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 1.9 billion therms in 2021.

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 $1.7 billion USD of assets and approximately 542,000 customers, NMGC serves approximately 60 per cent of New Mexico's population in 24 of the state's 33 counties. NMGC's system includes approximately 2,424 kilometres of transmission pipelines and 17,593 kilometres of distribution pipelines. Annual natural gas throughput was approximately 839 million therms in 2021.

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 2022 than 2021, primarily due to rate base growth to expand the distribution system and to continue to reliably serve customers. The PGS rate case settlement provides the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS has not reversed any of this accumulated depreciation to date. The reversal of accumulated depreciation is expected to occur over the 2022 and 2023 periods.

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 (following Florida's population growth and housing demands), PGS sales volumes in 2022 are expected to increase at a level consistent with customer growth.

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 February 2021, the State of New Mexico experienced an extreme cold weather event that resulted in an incremental $108 million USD for gas costs above what it would normally have paid during this period. NMGC normally recovers gas supply and related costs through a purchased gas adjustment clause. On April 16, 2021, NMGC filed a Motion for Extraordinary Relief, as permitted by the NMPRC rules, to extend the terms of the repayment of the incremental gas costs and to recover a carrying charge. On June 15, 2021 the NMPRC approved the recovery of $108 million USD and related borrowing costs over a period of 30 months beginning July 1, 2021.

In 2018, SeaCoast executed an agreement with Seminole Electric Cooperative, Inc. ("Seminole") to provide long-term firm gas transportation service to Seminole's new gas-fired generating facility being constructed in Putnam County, Florida. SeaCoast will operate a 21-mile, 30-inch pipeline lateral that will be treated as a sales-type lease for accounting purposes. The lease of the pipeline lateral to Seminole will commence in 2022. The capital investment is approximately $100 million USD, with the majority of the project investment completed through 2021.

In 2022, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $445 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

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 50.0 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 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, based on EES returning to its normal earnings range in 2022, higher operating, maintenance and general ("OM&G") expenses, lower realized foreign exchange gains on cash flow hedges and increased interest expense. The decrease is expected to be partially offset by decreased taxes due to a higher net loss.

In 2022, capital investment in the Other segment is expected to be $2 million (2021 – $1 million).

Consolidated Balance Sheet Highlights

Significant changes in the Consolidated Balance Sheets between December 31, 2020 and December 31, 2021 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	$ 174	Increased due to cash from operations, net issuances of debt at TEC, NMGC and GBPC, and issuance of preferred and common stock. This was partially offset by investments in property, plant and equipment and dividends on common stock.
Inventory	85	Increased due to higher commodity prices at Emera Energy, and higher fuel inventory and materials inventory at NSPI.
Derivative instruments (current and long-term)	203	Increased due to higher commodity prices and new derivative contracts, partially offset by settlements at NSPI.
Regulatory assets (current and long-term)	982	Increased due to the Tampa Electric capital cost recovery for early retired assets, increased deferrals related to the FAM and increased deferred income tax regulatory assets at NSPI, and the NMGC winter event gas cost recovery. These were partially offset by decreased pension and post-retirement plan deferrals at Tampa and PGS.
Receivables and other assets (current and long-term)	674	Increased due to higher cash collateral and trade receivables due to higher commodity prices and increased gas transportation assets at Emera Energy and higher pension and post-retirement assets at TEC and NSPI.
Property, plant and equipment, net of accumulated depreciation and amortization	818	Increased due to additions at Tampa Electric, PGS and NSPI, partially offset by the reclassification related to the Tampa Electric capital cost recovery for early retired assets.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	$ 1,054	Increased due to issuances of long-term debt at TEC, NMGC and GBPC and net issuance on committed credit facilities at TEC, NSPI and Corporate. These were partially offset by repayment of debt at TEC.
Accounts payable	337	Increased due to higher commodity prices at Emera Energy, higher natural gas prices at Tampa Electric, and increased cash collateral positions on derivative instruments at NSPI.
Deferred income tax liabilities, net of deferred income tax assets	153	Increased due to tax deductions in excess of accounting depreciation related to property, plant and equipment.
Derivative instruments (current and long-term)	344	Increased due to new contracts in 2021 and changes in existing positions, partially offset by reversal of 2020 contracts at Emera Energy.
Regulatory liabilities (current and long-term)	94	Increased due to deferrals related to derivative instruments at NSPI, partially offset by decreased deferred income tax regulatory liabilities, primarily due to amortization of excess deferred income taxes related to US Tax Reform at Tampa Electric, PGS and NMGC.
Pension and post-retirement liabilities	(83)	Decreased due to favourable changes in actuarial assumptions and higher investment returns on pension plan assets at NSPI.
Other liabilities (current and long-term)	113	Increased due to investment tax credits related to solar projects at Tampa Electric and emissions compliance charges at NSPI.
Common stock	537	Increased due to shares issued under Emera's at-the-market equity program and the dividend reinvestment plan.
Cumulative preferred stock	418	Increased due to issuances of preferred shares.
Accumulated other comprehensive income	104	Decrease in unrecognized pension and post-retirement benefit costs due to favourable changes in actuarial assumptions, higher than anticipated investment returns and amortization at NSPI, partially offset by the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Retained earnings	(147)	Decreased due to dividends paid in excess of net income.

Developments

Increase in Common Dividends

On September 24, 2021, the Emera Board of Directors approved an increase in the annual common share dividend rate to $2.65 from $2.55. The first payment was effective November 15, 2021. Emera also extended its dividend growth rate target of four to five per cent through 2024.

Tampa Electric Rate Case Settlement Agreement

On August 6, 2021, Tampa Electric filed with the FPSC a joint motion for approval of a Settlement Agreement by Tampa Electric and the intervenors in relation to its rate case filed with the FPSC in April 2021. The Settlement Agreement provides for a projected increase of $191 million USD in rates annually, effective with January 2022 bills. This increase will consist of $123 million USD in base rate charges and $68 million USD to recover the costs of retiring assets including Big Bend coal generation assets Units 1 through 3 and meter assets. The Settlement Agreement further includes two subsequent year adjustments of $90 million USD and $21 million USD, effective January 2023 and January 2024, respectively related to the recovery of future investments in the Big Bend Modernization project and solar generation. The allowed equity in the capital structure will continue to be 54 per cent from investor sources of capital. The Settlement Agreement includes an allowed regulated ROE range of 9.0 per cent to 11.0 per cent with a 9.95 per cent midpoint. On October 21, 2021, the FPSC approved the settlement agreement, and the final order reflecting such approval, was issued on November 10, 2021. For further information, refer to the "Business Overview and Outlook – Florida Electric Utility" section.

Delivery of NS Block

Nalcor's NS Block delivery obligations commenced on August 15, 2021, and delivery will continue 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 at a date to be agreed to by the companies. On August 9, 2021, NSPML filed a final capital cost application with the UARB seeking approval to recover capital costs associated with the Maritime Link and approval of NSPML's 2022 assessment. In December 2021, NSPML obtained an interim decision from the UARB approving interim rates beginning January 1, 2022, until receipt of the UARB's decision on the application. On February 9, 2022, the UARB issued its decision relating to the Maritime Link Project, approving NSPML's requested rate base of approximately $1.8 billion less costs that would not otherwise have been recoverable if incurred by NSPI. For further information on the NS Block and the UARB decision, refer to the "Business Overview and Outlook – Canadian Electric Utilities" and "Contractual Obligations" sections.

Preferred Shares

On September 24, 2021, Emera issued 9 million Cumulative Redeemable First Preferred Shares, Series L at $25.00 per share at an annual yield of 4.60 per cent. The aggregate gross and net proceeds from the offering were $225 million and $222 million, respectively. The net proceeds of the preferred share offering were used for general corporate purposes.

On April 6, 2021, Emera issued 8 million Cumulative Minimum Rate Reset First Preferred Shares, Series J at $25.00 per share at an initial dividend rate of 4.25 per cent. The aggregate gross and net proceeds from the offering were $200 million and $196 million, respectively. The net proceeds of the preferred share offering were used for general corporate purposes.

APPOINTMENTS

Board of Directors

Effective February 11, 2022, Paula Y. Gold-Williams joined the Emera Board of Directors. Ms. Gold-Williams is the former president and CEO of CPS Energy, the largest municipally-owned energy utility in the U.S., serving the city of San Antonio, Texas.

Effective February 11, 2022, Ian E. Robertson joined the Emera Board of Directors. Mr. Robertson is Chief Executive Officer of the Northern Genesis group of special purpose acquisition companies focused on identifying and acquiring energy transition businesses which demonstrate strong sustainability and Environmental, Social and Governance ("ESG") alignment. He is the former CEO of Algonquin Power & Utilities Corp., a publicly traded, diversified international generation, transmission, and distribution utility.

Effective August 10, 2021, Gil C. Quiniones joined the Emera Board of Directors. Mr. Quiniones is the former President and Chief Executive Officer of the New York Power Authority. Effective October 13, 2021, Mr. Quiniones resigned from the Emera Board of Directors following an appointment to a new senior executive position at a different organization.

Executive

On September 14, 2021, Emera announced that Helen Wesley was appointed President of PGS effective December 1, 2021. Ms. Wesley was most recently the Chief Operating Officer at PGS and succeeds T.J. Szelistowski who retired in December 2021.

Outstanding Common Stock Data

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars
Balance, December 31, 2019	242.48	$ 6,216
Issuance of common stock (1)	4.54	251
Issued for cash under Purchase Plans at market rate	3.99	219
Discount on shares purchased under Dividend Reinvestment Plan	–	(4)
Options exercised under senior management stock option plan	0.42	20
Employee Share Purchase Plan	–	3
Balance, December 31, 2020	251.43	$ 6,705
Issuance of common stock (2)	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**

(1) As at December 31, 2020, 4,544,025 common shares were issued under Emera's at-the-market program ("ATM program") at an average price of $56.04 per share for gross proceeds of $255 million ($251 million net of issuance costs).

(2) In Q4 2021, 1,247,300 common shares were issued under Emera's ATM program at an average price of $59.89 per share for gross proceeds of $74 million ($73 million net of after-tax issuance costs). For the year ended December 31, 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). As at December 31, 2021, an aggregate gross sales limit of $457 million remained available for issuance under the ATM program.

As at February 8, 2022, the amount of issued and outstanding common shares was 261.2 million.

The weighted average shares of common stock outstanding – basic, which includes both issued and outstanding common stock and outstanding deferred share units, for the three months ended December 31, 2021 was 260.8 million (2020 – 251.3 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2021 was 257.2 million (2020 – 247.8 million).

ATM Equity Program

On August 12, 2021, Emera renewed its ATM Program that allows the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was renewed pursuant to a prospectus supplement to the Company's short form base shelf prospectus dated August 5, 2021. The ATM program is expected to remain in effect until September 5, 2023.

Financial Highlights

FLORIDA ELECTRIC UTILITY

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended December 31 **2021**	 2020	Year ended December 31 **2021**	 2020
Operating revenues – regulated electric	**$ 561**	$ 468	**$ 2,174**	$ 1,849
Regulated fuel for generation and purchased power	**$ 212**	$ 127	**$ 713**	$ 428
Contribution to consolidated net income	**$ 67**	$ 76	**$ 369**	$ 372
Contribution to consolidated net income – CAD	**$ 85**	$ 101	**$ 462**	$ 501
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.33**	$ 0.40	**$ 1.80**	$ 2.02
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.25**	$ 1.31	**$ 1.25**	$ 1.34

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2020	**$ 76**	**$ 372**
Increased operating revenues – see Operating Revenues – Regulated Electric below	92	324
Increased fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power below	(85)	(285)
Increased OM&G expenses due to the timing of deferred clause recoveries, increased general consulting costs and higher insurance costs	(11)	(15)
Increased depreciation and amortization due to increase property, plant and equipment and a 2020 regulatory settlement	(7)	(35)
Increased AFUDC earnings due to the Big Bend Power Station modernization and solar projects	4	15
Other	(2)	(7)
Contribution to consolidated net income – 2021	**$ 67**	**$ 369**

Florida Electric Utility's CAD contribution to consolidated net income decreased $16 million in Q4 2021, compared to Q4 2020, and decreased $39 million in 2021, compared to 2020. Decreases in both periods were due to higher depreciation and amortization expense, reflecting increased capital investment and a 2020 regulatory settlement, the impact of a stronger CAD, and lower base revenue, partially offset by higher AFUDC earnings.

The impact of the change in the foreign exchange rate decreased CAD earnings for the quarter and year ended December 31, 2021 by $4 million and $34 million, respectively.

Operating Revenues – Regulated Electric

Electric revenues increased $93 million to $561 million in Q4 2021, compared to $468 million in Q4 2020, and increased $325 million to $2,174 million in 2021, compared to $1,849 million in 2020. Increases in both periods were due to higher fuel recovery clause revenue as a result of higher fuel costs, partially offset by lower base revenues resulting from less favourable weather compared to 2020.

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

Q4 Electric Revenues

millions of US dollars

	2021	2020
Residential	**$ 289**	$ 256
Commercial	**163**	132
Industrial	**48**	34
Other (1)	**61**	46
Total	**$ 561**	$ 468

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

Annual Electric Revenues

millions of US dollars

	2021	2020
Residential	**$ 1,156**	$ 1,018
Commercial	**602**	506
Industrial	**172**	133
Other (1)	**244**	192
Total	**$ 2,174**	$ 1,849

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

Q4 Electric Sales Volumes

Gigawatt hours ("GWh")

	2021	2020
Residential	**2,312**	2,465
Commercial	**1,525**	1,526
Industrial	**537**	460
Other	**501**	515
Total	**4,875**	4,966

Annual Electric Sales Volumes

GWh

	2021	2020
Residential	**9,941**	10,122
Commercial	**6,144**	6,058
Industrial	**2,122**	1,891
Other	**2,000**	1,958
Total	**20,207**	20,029

Regulated Fuel for Generation and Purchased Power

Tampa Electric is required to maintain a generating capacity greater than firm peak demand. The total Tampa Electric-owned generation capacity at December 31, 2021 is 5,919 MW. Tampa Electric meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

Regulated fuel for generation and purchased power increased $85 million to $212 million in Q4 2021, compared to $127 million in Q4 2020, and increased $285 million to $713 million in 2021, compared to $428 million in 2020. The increases in both periods were primarily due to increased natural gas prices.

Q4 Production Volumes

GWh

	2021	2020
Natural gas	**4,130**	3,616
Coal	**64**	344
Solar	**255**	232
Purchased power	**377**	747
Total	**4,826**	4,939

Annual Production Volumes

GWh

	2021	2020
Natural gas	**16,142**	16,523
Coal	**1,342**	904
Solar	**1,252**	1,120
Purchased power	**2,301**	2,513
Total	**21,037**	21,060

Q4 Average Fuel Costs

US dollars

	2021	2020
Dollars per Megawatt hour ("MWh")	**$ 44**	$ 26

Annual Average Fuel Costs

US dollars

	2021	2020
Dollars per MWh	**$ 34**	$ 20

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

Average fuel cost per MWh increased in Q4 2021 and for the year ended December 31, 2021, compared to the same periods 2020, primarily due to increased natural gas prices.

Regulatory Recovery Mechanisms

Tampa Electric is regulated by 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.

Solar Base Rate Adjustments Included in Base Rates

As of December 31, 2021, Tampa Electric has invested $850 million in 600 MW of utility-scale solar photovoltaic projects, which are recoverable through FPSC-approved solar base rate adjustments ("SoBRAs"). AFUDC was earned on these projects during construction. The FPSC has approved SoBRAs representing a total of 600 MW, or $104 million annually in estimated revenue requirements for in-service projects.

The true-up filing for SoBRAs tranche 1 and 2 revenue requirement estimates which were included in base rates as of September 2018 and January 2019, respectively, was submitted on April 30, 2020, and the FPSC approved the amount on August 18, 2020. A $5 million true-up was returned to customers in 2020. The true-up filing for SoBRA tranche 3, included in base rates as of January 2020, was approved by the FPSC on October 12, 2021. An estimated $4 million true-up was returned to customers during 2021. The true-up for SoBRA tranche 4 will be filed in early 2022.

Other Cost Recovery

Fuel Recovery Clause

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

Storm Protection Plan Cost Recovery Clause

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

Other Cost Recovery Clauses

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

Storm Reserve

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

Capital Cost Recovery for Early Retired Assets

This regulatory asset is related to the remaining net book value of Big Bend Power Station Units 1 through 3 and smart meter assets that were retired. The balance earns a rate of return as permitted by the FPSC and will be recovered as a separate line item on customer bills for a period of 15 years. This recovery mechanism is authorized by and survives the term of the settlement agreement approved by the FPSC in 2021.

CANADIAN ELECTRIC UTILITIES

For the millions of Canadian dollars (except per share amounts)		Three months ended December 31 **2021**		2020		Year ended December 31 **2021**		2020
Operating revenues – regulated electric	**$**	**389**	$	377	**$**	**1,501**	$	1,494
Regulated fuel for generation and purchased power (1)	**$**	**263**	$	219	**$**	**817**	$	721
Income from equity investments	**$**	**25**	$	21	**$**	**103**	$	96
Contribution to consolidated net income	**$**	**67**	$	57	**$**	**241**	$	221
Contribution to consolidated earnings per common share – basic	**$**	**0.26**	$	0.23	**$**	**0.94**	$	0.89

(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 net income is summarized in the following table:

For the millions of Canadian dollars		Three months ended December 31 **2021**		2020		Year ended December 31 **2021**		2020
NSPI	**$**	**43**	$	36	**$**	**141**	$	125
Equity investment in LIL		**14**		12		**51**		49
Equity investment in NSPML		**10**		9		**49**		47
Contribution to consolidated net income	**$**	**67**	$	57	**$**	**241**	$	221

Net Income

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

For the millions of Canadian dollars		Three months ended December 31		Year ended December 31
Contribution to consolidated net income – 2020	**$**	**57**	**$**	**221**
Increased operating revenues – see Operating Revenues – Regulated Electric below		12		7
Increased fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power below		(44)		(96)
Decreased FAM expense and fixed cost deferrals due to under-recovery of current period fuel costs compared to prior year's over-recovery of fuel costs, partially offset by the refund to customers in 2020 of prior years' fuel costs		40		101
Increased depreciation and amortization year-over-year due to increased property, plant and equipment		(1)		(10)
Decreased interest expense, net due to lower interest on the FAM regulatory deferral		1		7
Increased income tax expense quarter-over-quarter primarily due to increased income before provision for income taxes. Decreased income tax expense year-over-year primarily due to increased tax deductions in excess of accounting depreciation related to property, plant and equipment, partially offset by increased income before provision for income taxes.		(2)		7
Other		4		4
Contribution to consolidated net income – 2021	**$**	**67**	**$**	**241**

Canadian Electric Utilities' contribution to consolidated net income increased $10 million to $67 million in Q4 2021, compared to $57 million in Q4 2020, and increased $20 million to $241 million in 2021 compared to $221 million in 2020. Increases in both periods were primarily driven by higher contribution from NSPI. Quarter-over-quarter, the increase was primarily due to increased sales volumes. Year-over-year, the increase was primarily due to higher operating revenues, lower interest costs, and decreased income tax expense primarily due to tax deductions in excess of accounting depreciation related to property, plant and equipment. Increases were partially offset by higher depreciation and amortization.

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

NSPI

Operating Revenues – Regulated Electric

Operating revenues increased $12 million to $389 million in Q4 2021, compared to $377 million in Q4 2020 due to increased sales volume due to colder weather, fuel-related pricing, and increased customer sales volume, partially offset by lower Maritime Link assessment included in revenue compared to Q4 2020.

For the year ended December 31, 2021, operating revenues increased $7 million to $1,501 million, compared to $1,494 million in 2020 due to increased customer sales volume growth and fuel-related pricing, partially offset by lower Maritime Link assessment included in revenue compared to 2020.

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

Q4 Electric Revenues

millions of Canadian dollars	2021	2020
Residential	**$ 209**	$ 199
Commercial	**104**	102
Industrial	**61**	60
Other	**6**	7
Total	**$ 380**	$ 368

Annual Electric Revenues

millions of Canadian dollars	2021	2020
Residential	**$ 797**	$ 806
Commercial	**407**	405
Industrial	**237**	224
Other	**27**	31
Total	**$ 1,468**	$ 1,466

Q4 Electric Sales Volumes

GWh	2021	2020
Residential	**1,229**	1,159
Commercial	**730**	712
Industrial	**629**	629
Other	**38**	36
Total	**2,626**	2,536

Annual Electric Sales Volumes

GWh	2021	2020
Residential	**4,661**	4,652
Commercial	**2,902**	2,850
Industrial	**2,480**	2,341
Other	**153**	185
Total	**10,196**	10,028

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $44 million to $263 million in Q4 2021, compared to $219 million in Q4 2020, and increased $96 million to $817 million in 2021, compared to $721 million in 2020. Increases in both periods were due to a provision for the Nova Scotia Cap-and-Trade program and higher commodity prices. See below for further information. Quarter-over-quarter, increases were partially offset by decreases due to changes in generation mix driven by emissions constraints. Year-over-year, changes in generation mix and higher Maritime Link assessment costs also contributed to the increase.

The provision for the Nova Scotia Cap-and-Trade program was $35 million in Q4 2021 and $38 million for the year ended December 31, 2021. This is due to higher than expected emissions primarily as a result of the delayed timing of Muskrat Falls Energy. The expense is accrued over the compliance period based on forecast emissions for the 2019 through 2022 period and is an estimate of expected costs but does not represent a fixed obligation.

Q4 Production Volumes

GWh

	2021	2020
Coal	**1,224**	1,249
Natural gas	**371**	351
Purchased power – other	**196**	235
Petcoke	**208**	148
Oil	**14**	26
Total non-renewables	**2,013**	2,009
Purchased power	**536**	509
Wind and hydro	**243**	215
Biomass	**51**	21
Total renewables	**830**	745
Total production volumes	**2,843**	2,754

Annual Production Volumes

GWh

	2021	2020
Coal	**4,623**	4,342
Natural gas	**1,673**	1,872
Purchased power – other	**865**	663
Petcoke	**519**	927
Oil	**81**	40
Total non-renewables	**7,761**	7,844
Purchased power	**1,977**	1,808
Wind and hydro	**1,007**	1,001
Biomass	**160**	106
Total renewables	**3,144**	2,915
Total production volumes	**10,905**	10,759

Q4 Average Fuel Costs

	2021	2020
Dollars per MWh	**$ 93**	$ 80

Annual Average Fuel Costs

	2021	2020
Dollars per MWh	**$ 75**	$ 67

Average fuel cost per MWh increased in Q4 2021, and for the year ended December 31, 2021 compared to the same periods in 2020. Quarter-over-quarter average fuel costs increased primarily due to the recognition of GHG emission expense as part of the Nova Scotia Cap-and-Trade Program and increased commodity pricing. See above for further information. Year-over-year, average fuel costs also increased due to changes in generation mix from lower carbon intensity sources such as IPPs, import and biomass generation and decreased generation from solid fuel and natural gas. Year-over-year, a higher Maritime Link assessment cost also contributed to the increase.

NSPI's FAM regulatory balances increased $166 million, from a FAM regulatory liability of $21 million at December 31, 2020 to a FAM regulatory asset of $145 million at December 31, 2021, primarily due to under-recovery of current period fuel costs.

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

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

Regulatory Recovery Mechanisms

NSPI

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

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

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

As part of the three-year fuel stability plan, electricity rates have been set to include the $145 million approved Maritime Link assessment for 2020 and amounts of $164 million and $162 million for 2021 and 2022, respectively. On December 16, 2020, the UARB approved NSPML's application to recover from NSPI the costs associated with the Maritime Link in 2021 of approximately $172 million. This is subject to a holdback of $10 million, pending UARB agreement that benefits from the Maritime Link are realized for NSPI customers. NSPML has deferred collection and recognition of $23 million in depreciation expense in 2021. On August 9, 2021, NSPML filed a final cost application with the UARB to recover capital costs associated with the Maritime Link and approval of NSPML's 2022 assessment. In December 2021, NSPML obtained an interim decision from the UARB approving interim rates beginning January 1, 2022, until receipt of the UARB's decision on the application. On February 9, 2022, the UARB issued its decision relating to the Maritime Link Project, approving NSPML's requested rate base of approximately $1.8 billion less costs that would not otherwise have been recoverable if incurred by NSPI. For further information on the UARB decision, refer to the "Business Overview and Outlook – Canadian Electric Utilities" section. Any difference between the amounts included in the fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

OTHER ELECTRIC UTILITIES

All amounts are reported in USD, unless otherwise stated.

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

For the millions of US dollars (except per share amounts)	Three months ended December 31 **2021**	 2020	Year ended December 31 **2021**	 2020
Operating revenues – regulated electric	**$ 98**	$ 79	**$ 355**	$ 354
Regulated fuel for generation and purchased power (1)	**$ 52**	$ 35	**$ 175**	$ 145
Contribution to consolidated adjusted net income	**$ 4**	$ 5	**$ 16**	$ 24
Contribution to consolidated adjusted net income – CAD	**$ 5**	$ 8	**$ 20**	$ 33
Equity securities MTM gain	**$ 2**	$ 2	**$ 1**	$ 2
Contribution to consolidated net income	**$ 6**	$ 7	**$ 17**	$ 26
Contribution to consolidated net income – CAD	**$ 7**	$ 10	**$ 21**	$ 35
Contribution to consolidated adjusted earnings per common share – basic – CAD	**$ 0.02**	$ 0.03	**$ 0.08**	$ 0.13
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.03**	$ 0.04	**$ 0.08**	$ 0.14
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.27**	$ 1.28	**$ 1.26**	$ 1.34

(1) Regulated fuel for generation and purchased power includes transmission pool expense for year ended December 31, 2020 related to Emera Maine.

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

For the millions of US dollars	Three months ended December 31 **2021**	 2020	Year ended December 31 **2021**	 2020
BLPC	**$ 6**	$ 5	**$ 11**	$ 20
GBPC	**–**	3	**8**	5
Emera Maine	**–**	–	**–**	4
Other	**(2)**	(3)	**(3)**	(5)
Contribution to consolidated adjusted net income	**$ 4**	$ 5	**$ 16**	$ 24

Excluding the change in MTM, Other Electric Utilities CAD contribution to consolidated net income decreased $3 million to $5 million in Q4 2021, compared to $8 million in Q4 2020 and decreased $13 million to $20 million in 2021, compared to $33 million in 2020. Year-over-year, the decrease was due to the recognition of a previously deferred corporate income tax recovery at BLPC in Q1 2020 related to the enactment of a lower corporate income tax rate in December 2018 and the sale of Emera Maine in Q1 2020. These decreases were partially offset by higher income at GBPC and lower interest expense.

The foreign exchange rate had minimal impact for the three months December 31, 2021. For the year ended December 31, 2021, the strengthening of the CAD decreased earnings and adjusted earnings by $1 million.

Operating Revenues – Regulated Electric

Operating revenues increased $19 million to $98 million in Q4 2021, compared to $79 million in Q4 2020 and increased $1 million to $355 million in 2021, compared to $354 million in 2020. The increases in both periods were due to higher fuel revenue at BLPC due to higher fuel prices. Year-over-year, the increase was partially offset by the sale of Emera Maine.

Electric sales volumes were higher in Q4 2021 with 330 GWh compared to 313 GWh in Q4 2020. For the year ended December 31, 2021, electric sales volumes were higher with 1,262 GWh compared to 1,240 GWh in 2020.

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $17 million to $52 million in Q4 2021, compared to $35 million in Q4 2020 and increased $30 million to $175 million in 2021, compared to $145 million in 2020. The increases in both periods were due to higher fuel prices at BLPC. Year-over-year, the increase was partially offset by transmission pool expense at Emera Maine in 2020.

Regulatory Recovery Mechanisms

BLPC

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

GBPC

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

GBPC maintains insurance for its generation facilities. As with most utilities, its transmission and distribution networks are not covered by commercial insurance. In 2019, Hurricane Dorian restoration costs for GBPC transmission and distribution network assets were $15 million. In January 2020, the GBPA approved the deferral of these costs through a regulated asset with recovery through rates over a five-year period. Recovery of the asset began January 1, 2021.

As a result of Hurricane Matthew in 2016, a regulatory asset was established to recover associated restoration costs. In 2017, as part of the recovery of costs incurred as a result of Hurricane Matthew, the GBPA approved a fixed per kWh fuel charge and allowed the difference between this and the actual cost of fuel to be applied to the Hurricane Matthew regulatory asset. In September 2021, GBPC filed an application for rate review with the GBPA. As part of its decision issued January 14, 2022 and effective April 1, 2022, the GBPA approved the continued amortization of the remaining regulatory asset over the three year period ending December 31, 2024.

Domlec

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

GAS UTILITIES AND INFRASTRUCTURE

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended December 31 2021	2020	Year ended December 31 2021	2020
Operating revenues – regulated gas [(1)]	**$ 307**	$ 234	**$ 1,006**	$ 780
Operating revenues – non-regulated	**2**	3	**12**	12
Total operating revenue	**$ 309**	$ 237	**$ 1,018**	$ 792
Regulated cost of natural gas	**$ 139**	$ 80	**$ 375**	$ 221
Income from equity investments	**$ 4**	$ 4	**$ 16**	$ 14
Contribution to consolidated net income	**$ 44**	$ 35	**$ 157**	$ 122
Contribution to consolidated net income – CAD	**$ 55**	$ 45	**$ 198**	$ 162
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.21**	$ 0.18	**$ 0.77**	$ 0.65
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.26**	$ 1.30	**$ 1.26**	$ 1.33

(1) Operating revenues – regulated gas includes $12 million of finance income from Brunswick Pipeline (2020 – $11 million) for the three months ended December 31, 2021 and $46 million (2020 – $45 million) for the year ended December 31 2021; however, it is excluded from the gas revenues analysis below.

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

For the millions of US dollars	Three months ended December 31 2021	2020	Year ended December 31 2021	2020
PGS	**$ 17**	$ 13	**$ 77**	$ 52
NMGC	**15**	12	**33**	30
Other	**12**	10	**47**	40
Contribution to adjusted consolidated net income	**$ 44**	$ 35	**$ 157**	$ 122

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2020	**$ 35**	**$ 122**
Increased gas operating revenues – see Operating Revenues – Regulated Gas below	73	226
Increased cost of natural gas sold – see Regulated Cost of Natural Gas below	(58)	(153)
Increased OM&G expenses year-over-year primarily due to higher labour and insurance costs at PGS and NMGC	2	(10)
Increased depreciation and amortization expense due to increased property, plant and equipment	(3)	(14)
Other	(5)	(14)
Contribution to consolidated net income – 2021	**$ 44**	**$ 157**

Gas Utilities and Infrastructure's CAD contribution to consolidated net income increased $10 million in Q4 2021 to $55 million, compared to $45 million, in Q4 2020 and increased $36 million to $198 million compared to $162 million in 2020. The increases in both periods were due to higher base revenues at PGS as the result of a base rate increase effective January 1, 2021 and customer growth.

The impact of the change in the foreign exchange rate decreased CAD earnings for Q4 2021 and for the year ended December 31, 2021, by $1 million and $10 million respectively.

Operating Revenues – Regulated Gas

Gas Utilities and Infrastructure's operating revenues increased $73 million to $307 million in Q4 2021, compared to $234 million in Q4 2020 and increased $226 million to $1,006 million in 2021, compared to $780 million in 2020. The increases in both periods were due to a base rate increase at PGS and NMGC effective January 1, 2021, customer growth at PGS, and higher purchased gas adjustment clause revenues at PGS and NMGC as a result of higher gas prices.

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

Q4 Gas Revenues

millions of US dollars

		2021		2020
Residential	**$**	**167**	$	122
Commercial		**87**		63
Industrial (1)		**15**		11
Other (2)		**26**		27
Total (3)	**$**	**295**	$	223

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $12 million of finance income from Brunswick Pipeline (2020 – $11 million).

Annual Gas Revenues

millions of US dollars

		2021		2020
Residential	**$**	**510**	$	372
Commercial		**301**		207
Industrial (1)		**53**		41
Other (2)		**96**		115
Total (3)	**$**	**960**	$	735

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $46 million of finance income from Brunswick Pipeline (2020 – $45 million).

Q4 Gas Volumes

Therms (millions)

	2021	2020
Residential	**120**	132
Commercial	**212**	220
Industrial	**327**	388
Other	**27**	59
Total	**686**	799

Annual Gas Volumes

Therms (millions)

	2021	2020
Residential	**405**	405
Commercial	**799**	767
Industrial	**1,434**	1,586
Other	**137**	298
Total	**2,775**	3,056

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 to customers.

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

Regulated cost of natural gas increased $59 million to $139 million in Q4 2021, compared to $80 million in Q4 2020 and increased $154 million to $375 million in 2021, compared to $221 million in 2020. The increases in both periods were due to higher gas prices at PGS and NMGC.

Gas sales by type are summarized in the following table:

Q4 Gas Volumes by Type

Therms (millions)

	2021	2020
System supply	**177**	197
Transportation	**509**	602
Total	**686**	799

Annual Gas Volumes by Type

Therms (millions)

	2021	2020
System supply	**621**	690
Transportation	**2,154**	2,366
Total	**2,775**	3,056

Regulatory Recovery Mechanisms

PGS

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

Other Cost Recovery

Fuel Recovery Clause

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

Other Cost Recovery Clauses

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

NMGC

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

Other Cost Recovery

Fuel Recovery Clause

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

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

NMGC Winter Event Gas Cost Recovery

In February 2021, the State of New Mexico experienced an extreme cold weather event that resulted in an incremental $108 million for gas costs above what NMGC would normally have paid during this period. On June 15, 2021, the NMPRC approved the recovery over a period of 30 months beginning July 1, 2021. For more information, refer to the "Business Overview and Outlook – Gas Utilities and Infrastructure" section.

Weather Normalization Mechanism

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

IMP Regulatory Asset

A portion of NMGC's annual spend on infrastructure is for integrity management programs ("IMP"), or the replacement and update of legacy systems. These programs are driven both by NMGC integrity management plans and federal and state mandates. In December 2020, NMGC received approval through its rate case to defer costs through an IMP regulatory asset for certain of its IMP capital investments occurring between January 1, 2022 and December 31, 2023, and is seeking recovery of the regulatory asset in its rate case filed on December 13, 2021.

OTHER

For the millions of Canadian dollars (except per share amounts)		Three months ended December 31 **2021**		2020		Year ended December 31 **2021**		2020
Marketing and trading margin (1) (2)	**$**	**39**	$	22	**$**	**102**	$	38
Other non-regulated operating revenue		**5**		12		**30**		37
Total operating revenues – non-regulated	**$**	**44**	$	34	**$**	**132**	$	75
Income from equity investments	**$**	**–**	$	7	**$**	**12**	$	24
Contribution to consolidated adjusted net income (loss)	**$**	**(44)**	$	(23)	**$**	**(198)**	$	(252)
Gain on sale, net of tax and transaction costs (3)		**–**		–		**–**		309
Impairment charges, net of tax (4)		**–**		–		**–**		(26)
After-tax derivative MTM gain (loss) (5)		**154**		83		**(214)**		(12)
Contribution to consolidated net income (loss)	**$**	**110**	$	60	**$**	**(412)**	$	19
Contribution to consolidated adjusted earnings per common share – basic	**$**	**(0.17)**	$	(0.09)	**$**	**(0.77)**	$	(1.02)
Contribution to consolidated earnings per common share – basic	**$**	**0.42**	$	0.24	**$**	**(1.60)**	$	0.08

(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 $212 million in Q4 2021 (2020 – $109 million gain) and a loss of $289 million for the year ended December 31,2021 (2020 – $46 million loss).
(3) Net of income tax expense of $276 million for the year ended December 31, 2020.
(4) Net of income tax expense of $1 million for the year ended December 31, 2020.
(5) Net of income tax expense of $63 million for the three months ended December 31, 2021 (2020 – $33 million expense) and $86 million recovery for the year ended December 31, 2021 (2020 – $8 million recovery).

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

For the millions of Canadian dollars		Three months ended December 31 **2021**		2020		Year ended December 31 **2021**		2020
Emera Energy	**$**	**17**	$	15	**$**	**54**	$	17
Corporate – see breakdown of adjusted contribution below		**(57)**		(32)		**(231)**		(255)
Emera Technologies		**(4)**		(5)		**(17)**		(12)
Other		**–**		(1)		**(4)**		(2)
Contribution to consolidated adjusted net income (loss)	**$**	**(44)**	$	(23)	**$**	**(198)**	$	(252)

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

Net Income

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

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income (loss) – 2020	**$ 60**	**$ 19**
Increased marketing and trading margin – see Emera Energy below	17	64
Decreased interest expense in both periods due to the impact of a stronger CAD and lower interest rates. Year-over-year also decreased due to the repayment of corporate debt	6	35
Realized gain on hedges entered into to hedge foreign exchange earnings exposure	2	19
Revaluation of net deferred income tax assets and liabilities resulting from the enactment of a lower Nova Scotia provincial corporate income tax rate in Q1 2020, including $2 million recovery related to MTM	–	11
TGH award, net of tax and legal costs	(36)	(36)
Decreased income tax recovery primarily due to decreased losses before provision for income taxes.	(7)	(39)
Increased MTM gains, net of tax, quarter-over-quarter, primarily due to settlements and changes in existing positions at Emera Energy. These were partially offset by higher amortization on gas transportation assets in Q4 2021 and the reversal of 2020 foreign exchange gains on cash flow hedges. Increased MTM losses, net of tax, year-over-year, primarily due to changes in existing positions and the reversal of 2020 foreign exchange gains on cash flow hedges.	71	(200)
2020 gain on sale and impairment charges, net of tax	–	(283)
Other	(3)	(2)
Contribution to consolidated net income (loss) – 2021	**$ 110**	**$ (412)**

Emera Energy

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

Marketing and Trading

Excluding the impact of MTM gains, marketing and trading margin increased $17 million in Q4 2021, compared to Q4 2020, due to higher spot and forward natural gas prices and increased volatility, which created profitable opportunity for Emera Energy's transportation and storage portfolio.

For the year ended December 31, 2021, marketing and trading margin, excluding the impact of MTM losses, increased $64 million compared to 2020. This increase reflected the mid-February extreme weather event across the South-Central US which sharply increased pricing and volatility in adjacent markets where Emera Energy has a presence, and on which the business was able to capitalize. In addition, Q3 and Q4 presented opportunity, with a surge in global liquefied natural gas ("LNG") pricing in particular enhancing gas market pricing and volatility in key geographies.

Corporate

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

For the millions of Canadian dollars	Three months ended December 31 **2021**	 2020	Year ended December 31 **2021**	 2020
Operating expenses (1)	**$ 1**	$ 17	**$ 28**	$ 54
Interest expense	**65**	71	**264**	299
Income tax recovery	**(18)**	(24)	**(75)**	(102)
Preferred dividends	**14**	11	**50**	45
TGH award	**–**	(36)	**–**	(36)
Income tax expense associated with the revaluation of Corporate deferred income tax assets and liabilities due to the 2020 reduction in the Nova Scotia provincial corporate income tax rate	**–**	–	**–**	9
Other (2)	**(5)**	(7)	**(36)**	(14)
Corporate adjusted net loss	**$ (57)**	$ (32)	**$ (231)**	$ (255)

(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 foreign exchange gains on cash flow hedges to hedge foreign exchange earnings exposure, Q4 2021 includes a $5 million gain (2020 – $2 million gain) and year-ended December 31, 2021 gain of $18 million (2020 – $2 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 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.

The ongoing COVID-19 pandemic, including government measures to address the pandemic, have resulted in economic slowdowns in all markets served by Emera. The pace and strength of economic recovery varies among jurisdictions. On a consolidated basis, COVID-19 has not had a material financial impact to net earnings in 2021 and is not expected to have a material financial impact in 2022. For further information on the potential future impacts of COVID on Emera and its businesses, refer to the "Business Overview and Outlook" section.

There have been no significant customer defaults to date and as of December 31, 2021. Adjustments to the allowance for credit losses have increased but have not had a material impact on earnings. The full impact of potential credit losses due to customer non-payment is not known at this time but is not expected to be material. The utilities are continuing to monitor customer accounts and are working with customers on payment arrangements.

The Company currently expects to continue to have adequate liquidity given its cash position, existing bank facilities, and access to capital, but will continue to monitor the impact of COVID-19 on future cash flows.

Emera's future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera has a $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. The extent of the future impact of COVID-19 on the profile of the Company's capital investment plan cannot be predicted at this time. The Company has flexibility with respect to its capital investment plan and will continue to monitor current events and related impacts of COVID-19.

Emera plans to use cash from operations and debt raised at the utilities to support normal operations, repayment of existing debt, and capital requirements. Debt raised at certain of the Company's utilities is subject to applicable regulatory approvals. Equity requirements in support of the Company's capital investment plan 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 $1.4 billion undrawn and available at December 31, 2021. The Company was holding a cash balance of $417 million at December 31, 2021. For further discussion, refer to the "Debt Management" section below. Refer to notes 23 and 25 in the consolidated financial statements for additional information regarding the credit facilities.

CONSOLIDATED CASH FLOW HIGHLIGHTS

Significant changes in the Consolidated Statements of Cash Flows between the years ended December 31, 2021 and 2020 include:

millions of Canadian dollars	2021	2020	$ Change
Cash, cash equivalents and restricted cash, beginning of period	**$ 254**	$ 274	$ (20)
Provided by (used in):			
Operating cash flow before changes in working capital	**1,337**	1,420	(83)
Change in working capital	**(152)**	217	(369)
Operating activities	**$ 1,185**	$ 1,637	$ (452)
Investing activities	**(2,332)**	(1,224)	(1,108)
Financing activities	**1,311**	(372)	1,683
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**(1)**	(61)	60
Cash, cash equivalents, and restricted cash, end of period	**$ 417**	$ 254	$ 163

Cash Flow from Operating Activities

Net cash provided by operating activities decreased $452 million to $1,185 million for the year ended December 31, 2021, compared to $1,637 million in 2020.

Cash from operations before changes in working capital decreased $83 million in 2021. The decrease was primarily due to the deferral of gas costs at NMGC resulting from the February 2021 extreme cold weather event, higher under-recovery of clause-related costs primarily due to higher natural gas prices at Tampa Electric and PGS, the TGH award in 2020, and the sale of Emera Maine in Q1 2020. This was partially offset by increased marketing and trading margin at Emera Energy and higher base revenue at PGS.

Changes in working capital decreased operating cash flows by $369 million due to unfavourable changes in cash collateral positions at Emera Energy, increased fuel inventory at Emera Energy and NSPI, unfavourable changes in accounts receivable at Tampa Electric and NMGC, the receipt of a 2019 income tax refund at NSPI in 2020, and timing of accounts payable payments at NMGC and PGS. This was partially offset by favourable changes in cash collateral positions on derivative instruments at NSPI.

Cash Flow Used in Investing Activities

Net cash used in investing activities increased $1,108 million to $2,332 million for the year ended December 31, 2021, compared to $1,224 million in 2020. The increase was due to the proceeds of $1.4 billion received on the sale of Emera Maine in 2020, partially offset by lower capital expenditures in 2021.

Capital expenditures for the year ended December 31, 2021, including AFUDC, were $2,420 million compared to $2,668 million in 2020. Details of the 2021 capital spend by segment are shown below:

- $1,408 million – Florida Electric Utility (2020 – $1,415 million);
- $374 million – Canadian Electric Utilities (2020 – $342 million);
- $111 million – Other Electric Utilities (2020 – $149 million);
- $522 million – Gas Utilities and Infrastructure (2020 – $758 million); and
- $5 million – Other (2020 – $4 million).

Cash Flow from Financing Activities

Net cash provided by financing activities increased $1,683 million to $1,311 million for the year ended December 31, 2021, compared to cash used in financing activities of $372 million in 2020. The increase was due to net proceeds from the issuance of long-term debt at Tampa Electric, NMGC, PGS and GBPC in 2021, repayment of long-term debt at TECO Finance in 2020, lower net repayments of committed credit facilities at TECO Finance and Emera, and the issuance of preferred shares. This was partially offset by higher net repayments of short-term debt at TEC and net proceeds from long-term debt in 2020 at NSPI.

WORKING CAPITAL

As at December 31, 2021, Emera's cash and cash equivalents were $394 million (2020 – $220 million) and Emera's investment in non-cash working capital was $491 million (2020 – $266 million). Of the cash and cash equivalents held at December 31, 2021, $194 million was held by Emera's foreign subsidiaries (2020 – $197 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, 2021, 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	$ 462	$ 590	$ 827	$ 504	$ 3,479	$ 8,914	$ 14,776
Interest payment obligations (1)	611	592	580	561	481	6,589	9,414
Transportation (2)	563	437	372	323	297	2,627	4,619
Purchased power (3)	231	227	244	242	235	1,967	3,146
Fuel, gas supply and storage	694	104	45	40	25	–	908
Capital projects	359	93	3	1	1	–	457
Asset retirement obligations	8	7	2	2	1	395	415
Long-term service agreements (4)	49	66	47	32	26	83	303
Pension and post-retirement obligations (5)	32	38	33	33	33	168	337
Equity investment commitments (6)	240	–	–	–	–	–	240
Leases and other (7)	15	14	14	12	4	116	175
Demand side management	44	1	1	–	–	–	46
Long-term payable	5	5	–	–	–	–	10
	$ 3,313	$ 2,174	$ 2,168	$ 1,750	$ 4,582	$ 20,859	$ 34,846

(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, 2021, 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 $142 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.
(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. As part of NSPI's 2020 through 2022 fuel stability plan, rates have been set to include $164 million and $162 million for 2021 and 2022, respectively. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval. Any difference between the amounts included in the NSPI fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM. On August 9, 2021, NSPML filed a final capital cost application with the UARB seeking approval to recover capital costs associated with the Maritime Link and approval of NSPML's 2022 assessment. In December 2021, NSPML obtained an interim decision from the UARB approving interim rates beginning January 1, 2022, until receipt of the UARB's decision on the application. On February 9, 2022, the UARB issued its decision relating to the Maritime Link Project, approving NSPML's requested rate base of approximately $1.8 billion less costs that would not otherwise have been recoverable if incurred by NSPI. For further information on the UARB decision, refer to the "Business Overview and Outlook – Canadian Electric Utilities" section.

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

Emera has committed to obtain certain transmission rights for Nalcor, 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 commenced, and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Leases and other" in the above table.

FORECASTED GROSS CONSOLIDATED CAPITAL EXPENDITURES

2022 forecasted gross consolidated capital expenditures are as follows:

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Total
Generation	$ 352	$ 170	$ 47	$ –	$ –	$ 569
New renewable generation	306	30	20	–	–	356
Transmission	80	150	2	–	–	232
Distribution	505	110	48	–	–	663
Gas transmission and distribution	–	–	–	562	–	562
Facilities, equipment, vehicles, and other	172	70	11	–	2	255
	$ 1,415	$ 530	$ 128	$ 562	$ 2	$ 2,637

DEBT MANAGEMENT

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.8 billion committed syndicated bank credit facilities in either CAD or USD per the table below.

millions of dollars	Maturity	Revolving Credit Facilities	Utilized	Undrawn and Available
Emera – Unsecured committed revolving credit facility	June 2026	$ 900	$ 493	$ 407
TEC (in USD) – Unsecured committed revolving credit facility (1)	December 2026	800	246	554
NSPI – Unsecured committed revolving credit facility	December 2026	600	385	215
Emera – Unsecured non-revolving facility	December 2022	400	400	–
TEC (in USD) – Unsecured non-revolving facility (2)	December 2022	500	500	–
TECO Finance (in USD) – Unsecured committed revolving credit facility	December 2026	400	280	120
NMGC (in USD) – Unsecured committed revolving credit facility	December 2026	125	22	103
NMGC (in USD) – Unsecured non-revolving facility	September 2022	80	80	–
Other (in USD) – Unsecured committed revolving credit facilities	Various	34	20	14

(1) This facility is available for use by Tampa Electric and PGS. At December 31, 2021, $156 million USD was used by Tampa Electric and $90 million USD was used by PGS.

(2) This facility is available for use by Tampa Electric and PGS. At December 31, 2021, $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 December 31, 2021. Emera's significant covenant is listed below:

	Financial Covenant	Requirement	As at December 31, 2021
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.57 : 1

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

Florida Electric Utilities

On December 17, 2021, TEC entered into a $500 million USD unsecured, non-revolving credit facility with a maturity date of December 16, 2022. The credit facility contains customary representations and warranties, events of default, financial and other covenants and bears interest based on either the London Inter-Bank Offered Rate ("LIBOR"), prime rate, or the federal funds rate, plus a margin.

On December 17, 2021, TEC amended and restated its $800 million USD revolving credit facility. The amendment extended the maturity date from March 22, 2023 to December 17, 2026. There were no other significant changes in commercial terms from the prior agreement.

On May 25, 2021, TEC established a commercial paper program. Amounts available under the commercial paper program may be borrowed, repaid and reborrowed with the aggregate amount of the notes outstanding at any time not to exceed $800 million USD. The full amount of commercial paper issued is backed by TEC's credit facility and results in an equal amount of its credit facility being considered drawn and unavailable.

On May 15, 2021, TEC repaid its $278 million USD, 5.4 per cent notes upon maturity. The notes were repaid using existing credit facilities.

On March 18, 2021, TEC completed an issuance of $800 million USD senior notes. The issuance included $400 million USD senior notes that bear interest at a rate of 2.40 per cent with a maturity date of March 15, 2031 and $400 million USD senior notes that bear interest at a rate of 3.45 per cent with a maturity date of March 15, 2051.

As a result of the $800 million USD senior notes issuance discussed above, on March 23, 2021, TEC repaid its $300 million USD non-revolving term loan. TEC also repaid its $150 million USD accounts receivable collateralized borrowing facility and the agreement subsequently matured and terminated on March 22, 2021.

Canadian Electric Utilities

On December 3, 2021, NSPI amended its operating credit facility to extend the maturity from October 2024 to December 2026. There were no other significant changes in commercial terms from the prior agreement.

Other Electric Utilities

On December 16, 2021, GBPC entered into a $75 million USD 4.00 per cent term loan with a maturity date of December 31, 2026. Proceeds from this loan were used to repay existing, non-revolving term loans totaling $55 million USD and to fund operations.

Gas Utilities and Infrastructure

On December 17, 2021, NMGC amended and restated its $125 million USD revolving credit facility. The amendment extended the maturity date from March 22, 2023 to December 17, 2026. There were no other significant changes in commercial terms from the prior agreement.

On July 16, 2021, Brunswick Pipeline extended the maturity date of its $250 million credit facility from May 17, 2023 to June 30, 2025. There were no other significant changes in commercial terms from the prior agreement.

On March 25, 2021, NMGC entered into a $100 million USD unsecured, non-revolving credit facility with a maturity date of September 23, 2022. The credit facility contains customary representations and warranties, events of default, financial and other covenants and bears interest based on either the LIBOR, prime rate, or the federal funds rate, plus a margin. Proceeds from this issuance were used to pay for higher than normal gas costs as a result of the severe cold weather event in February 2021 (for more detail, refer to "Business Overview and Outlook – Gas Utilities and Infrastructure" section).

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

Other

On December 17, 2021, TECO Finance amended and restated its $400 million USD revolving credit facility. The amendment extended the maturity date from March 22, 2023 to December 17, 2026. There were no other significant changes in commercial terms from the prior agreement.

On December 3, 2021, Emera extended the maturity date of its $400 million non-revolving term loan from December 16, 2021 to December 16, 2022. There were no other significant changes in commercial terms from the prior agreement.

On July 23, 2021, Emera extended the maturity date of its $900 million unsecured committed revolving credit facility from June 30, 2024 to June 30, 2026. There were no other significant changes in commercial terms from the prior agreement.

On June 4, 2021, Emera US Finance LP completed an issuance of $750 million USD senior notes. The issuance included $450 million USD senior notes that bear interest at a rate of 2.64 per cent with a maturity date of June 15, 2031 and $300 million USD senior notes that bear interest at a rate of 0.83 per cent with a maturity date of June 15, 2024. The USD senior notes are guaranteed by Emera and Emera US Holdings Inc., a wholly owned Emera subsidiary.

From the $750 million USD senior notes issuance discussed above, on June 15, 2021, Emera US Finance LP repaid its previously outstanding $750 million USD senior notes on maturity.

Preferred Share Issuances

On September 24, 2021, Emera issued 9 million Cumulative Redeemable First Preferred Shares, Series L at $25.00 per share at an annual yield of 4.60 per cent. The aggregate gross and net proceeds from the offering were $225 million and $222 million, respectively.

On April 6, 2021, Emera issued 8 million Cumulative Minimum Rate Reset First Preferred Shares, Series J at $25.00 per share at an initial dividend rate of 4.25 per cent. The aggregate gross and net proceeds from the offering were $200 million and $196 million, respectively.

CREDIT RATINGS

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

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

GUARANTEED DEBT

On June 4, 2021, Emera US Finance LP completed an issuance of $750 million USD senior notes. From the proceeds of the issuance, on June 15, 2021, Emera US Finance LP repaid its previously outstanding $750 million USD senior notes on maturity. As of December 31, 2021, 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.

On January 1, 2021 the Company adopted *ASU 2020-09, Debt (Topic 470): Amendments to SEC Paragraphs pursuant to SEC Release No 33-10762*. In the release, the SEC adopted final rules that amend the financial disclosure requirements for subsidiary issuers and guarantors of registered debt securities under Rule 3-10 of Regulation S-X, permitting registrants to disclose summarized financial information for each subsidiary issuer and guarantor. These rules were codified in Rule 13-01 of Regulation S-X. In compliance thereof, 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 include 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 Canadian dollars	Year ended December 31 2021
Loss from operations	$ (21)
Net losses (1)	$ (86)

(1) Includes $222 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 Canadian dollars	December 31 2021
Current assets (1)	$ 329
Goodwill	5,628
Other assets (2)	6,027
Total assets (3)	$ 11,984
Current liabilities (4)	$ 888
Long-term liabilities (5)	6,403
Total liabilities	$ 7,291

(1) Includes $140 million in amounts due from non-guarantor subsidiaries.
(2) Includes $5,749 million in amounts due from non-guarantor subsidiaries.
(3) Excludes investments in non-guarantor subsidiaries. Consolidated Emera total assets are $34,244 million.
(4) Includes $346 million due to non-guarantor subsidiaries.
(5) Includes $776 million due to non-guarantor subsidiaries.

SHARE CAPITAL

Emera

As at December 31, 2021, Emera had 261.07 million (2020 – 251.43 million) common shares issued and outstanding. For the year ended December 31, 2021, 9.64 million common shares were issued (2020 – 8.95 million) for net proceeds of $537 million (2020 – $489 million).

As at December 31, 2021, Emera had 58 million preferred shares issued and outstanding (2020 – 41 million).

Pension Funding

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three-year period. The cash required in 2022 for defined benefit pension plans is expected to be $41 million (2021 – $41 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

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

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

Emera's projected contributions to defined contribution pension plans, are $46 million for 2022 (2021 – $45 million).

DEFINED BENEFIT PENSION PLAN SUMMARY

millions of Canadian dollars

Plans by region	TECO Energy	NSPI	Caribbean	Total
Assets as at December 31, 2021	$ 1,171	$ 1,521	$ 10	$ 2,702
Accounting obligation at December 31, 2021	$ 1,078	$ 1,531	$ 15	$ 2,624
Accounting expense during fiscal 2021	$ 13	$ 9	$ 1	$ 23

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, 2021 totalled $200 million (2020 – $582 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, 2021:

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 on January 1, 2022. In the event that TECO Energy's and Emera's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of $27 million USD.

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

NSPI has issued guarantees in the amount of $15 million USD on behalf of its subsidiary, NS Power Energy Marketing Incorporated ("NSPEMI"), to secure obligations under purchase agreements with third-party suppliers and $85 million USD related to a 15-year natural gas transportation commitment. NSPI has $118 million USD (2020 – $18 million USD) of guarantees outstanding with terms of varying lengths and will be renewed as required.

The Company has standby letters of credit and surety bonds in the amount of $148 million USD (December 31, 2020 – $55 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 2022. The amount committed as at December 31, 2021 was $64 million (December 31, 2020 – $63 million).

Dividend Payout Ratio

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. Emera Incorporated's common share dividends paid in 2021 were $2.5750 ($0.6375 in Q1, Q2, and Q3 and $0.6625 in Q4) per common share and $2.4750 ($0.6125 in Q1, Q2, and Q3 and $0.6375 in Q4) per common share for 2020, representing a dividend payout ratio of 129 per cent in 2021 (2020 – 65 per cent) and a dividend payout ratio of adjusted net income of 91 per cent in 2021 (2020 – 91 per cent).

On September 24, 2021, the Emera Board of Directors approved an increase in the annual common share dividend rate to $2.65 from $2.55. The first quarterly dividend payment at the increased rate was paid on November 15, 2021.

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 $149 million for the year ended December 31, 2021 (2020 – $139 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 $19 million for the year ended December 31, 2021 (2020 – $18 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, 2021 and at December 31, 2020.

Enterprise Risk and Risk Management

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

The 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 change in regulatory frameworks, shifts in government policy, and regulatory decisions.

As cost-of-service utilities with an obligation to serve customers, Emera's utilities operate under formal regulatory frameworks, and must obtain regulatory approval to change or add rates and/or riders. Costs and investments can be recovered upon approval by the respective regulator as an adjustment to rates and/or riders, which normally requires a public hearing process or may be mandated by other governmental bodies. Emera also holds investments in entities in which it has significant influence, and which are subject to regulatory and political risk including NSPML, LIL, M&NP and Lucelec.

As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the CER on a complaint basis, as opposed to the regulatory approval process described above. In the absence of a complaint, the CER does not normally undertake a detailed examination of Brunswick Pipeline's tolls, which are subject to a firm service agreement expiring in 2034, with Repsol Energy Canada ("REC"). The agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract.

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

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

GLOBAL CLIMATE CHANGE RISK

The Company is subject to risks that may arise from the impacts of climate change. There is increasing public concern about climate change and growing support for reducing carbon 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 the 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 is on track to achieve reductions of carbon dioxide emissions of approximately 60 per cent from 2005 levels. NSPI expects to exceed the new 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 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. 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 contributes to risk mitigation, as does insurance coverage (for assets other than electricity transmission and distribution assets). In addition, implementation of regulatory mechanisms for recovery of costs, such as storm reserves and regulatory deferral accounts, help to smooth out the recovery of storm restoration costs over time.

Reputation

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

Markets

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

Given concerns regarding carbon-emitting generation, those assets and businesses may, over time, become difficult (or uneconomic) to insure in commercial insurance markets. In the short term, this may be mitigated through increased investment in engineered protection or alternative risk financing (such as funded self-insurance or regulatory structures, including storm reserves). Longer-term mitigation may be achieved through infrastructure siting decisions and further engineered protections. This risk is also mitigated through the continued transition away from high-carbon generation sources to sources with low or zero carbon 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 committed to compliance with all climate-related and environmental legislative and regulatory requirements. Such legislative and regulatory initiatives could adversely affect Emera's operations and financial performance. Refer to "Regulatory and Political Risk" and "Changes in Environmental Legislation" risk. The Company seeks to mitigate these risks through active engagement with governments and regulators to pursue transition strategies that meet the needs of customers, stakeholders and the Company. This has included NSPI's participation in negotiated equivalency agreements in Nova Scotia to provide for an affordable transition to lower-carbon generation. Equivalency agreements allow NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent.

Regulatory

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

Legal

The Company could face litigation or regulatory action related to environmental harms from carbon 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, electrical utilities operating in Atlantic Canada could see lower demand in winter months if temperatures are warmer than expected. Further, extreme weather conditions such as hurricanes and other severe weather conditions which may be associated with climate change could cause these seasonal fluctuations to be more pronounced. In the absence of a regulatory recovery mechanism for unanticipated costs, such events could influence the Company's results of operations, financial conditions or cash flows.

Extreme weather events create a risk of physical damage to the Company's assets. High winds can impact structures and cause widespread damage to transmission and distribution infrastructure, 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.

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

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

CHANGES IN ENVIRONMENTAL LEGISLATION

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

In 2019, NSPI completed registration under the Nova Scotia Cap-and-Trade Program Regulations. This provincial carbon pricing program meets the benchmark set by the Government of Canada. In the United States, air emissions, including GHG emissions, are regulated pursuant to the Clean Air Act. Individual states continue to develop or administer GHG reduction initiatives. Changes to GHG emissions standards and air emissions standards could adversely affect Emera's operations and financial performance. Legislative or regulatory changes could influence decisions regarding early retirement of generation facilities and may result in stranded costs if the Company is not able to fully recover the costs and investment in the affected generation assets. Recovery is not assured and is subject to prudency review. Legislative or regulatory changes may curtail sales of natural gas to new customers, which could reduce future customer growth in Emera's natural gas businesses. Stricter environmental laws and enforcement of such laws in the future could increase Emera's exposure to additional liabilities and costs. These changes could also affect earnings and strategy by changing the nature and timing of capital investments.

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

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

CYBERSECURITY RISK

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

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

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

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

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

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

FOREIGN EXCHANGE RISK

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

Consistent with the Company's risk management policies, Emera manages currency risks through matching US denominated debt to finance its US operations and may use foreign currency derivative instruments to hedge specific transactions and earnings exposure. The Company may enter foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, 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 foreign exchange.

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

LIQUIDITY AND CAPITAL MARKET RISK

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

Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in property, plant and equipment and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The 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 and regulatory framework, the ability to recover costs and earn returns, diversification, leverage, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes and other severe weather events. A decrease in a credit rating could result in higher interest rates in future financings, increase borrowing costs under certain existing credit facilities, limit access to the commercial paper market or limit the availability of adequate credit support for subsidiary operations. For certain derivative instruments, if the credit ratings of the Company were reduced below investment grade, the full value of the net liability of these positions could be required to be posted as collateral. Emera manages these risks by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

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

INTEREST RATE RISK

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

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

PROJECT DEVELOPMENT AND LAND USE RIGHTS RISK

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

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

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

COUNTERPARTY RISK

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

Emera manages this counterparty risk through due diligence and 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. Emera may also seek recovery of unpaid amounts or damages through applicable bankruptcy, insolvency or similar proceedings.

COUNTRY RISK

Earnings outside of Canada constituted 78 per cent of Emera's earnings in 2021 (2020 – 73 per cent) with the majority from the US. Emera's investments are currently in regions where political and economic risks are considered by the Company to be acceptable. Emera's operations in some countries may be subject to changes in economic growth, restrictions on the repatriation of income or capital exchange controls, inflation, the effect of global health, safety and environmental matters, including climate change, or economic conditions and market conditions, and change in financial policy and availability of credit. The Company mitigates this risk through a rigorous approval process for investment, and by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available in all affiliates.

COMMODITY PRICE RISK

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

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

Regulated Utilities

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

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

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.

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, 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. Two of the largest drivers of cost are investment performance and interest rates, which are affected by global financial and capital markets. Depending on future interest rates and actual versus expected investment performance, Emera could be required to make larger contributions in the future to fund these plans, which could affect Emera's cash flows, financial condition and operations.

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

LABOUR RISK

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

Approximately 33 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have an adverse effect on the Company's earnings, cash flow and financial position. Emera seeks to manage this risk through ongoing discussions and working to maintain positive relationships with local unions. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labour disruption.

INFORMATION TECHNOLOGY RISK

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

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

INCOME TAX RISK

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

SYSTEM OPERATING AND MAINTENANCE RISKS

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

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

UNINSURED RISK

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

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

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

Risk Management including Financial Instruments

Emera's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are overseen by the Board of Directors. The Company has established a number of processes and practices to identify, monitor, report on and mitigate material risks to the Company. This includes establishment of the Enterprise Risk Management Committee, whose responsibilities include preparing an updated risk dashboard and heat map 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 exposure to normal operating and market risks relating to commodity prices, foreign exchange, interest rates and share prices through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of foreign exchange forwards and swaps, interest rate options and swaps, equity derivatives, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. Collectively, these contracts and financial instruments are considered derivatives.

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

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

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

HEDGING ITEMS RECOGNIZED ON THE BALANCE SHEETS

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

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Derivative instrument assets (current and other assets)	**$ –**	$ 1
Net derivative instrument assets	**$ –**	$ 1

HEDGING IMPACT RECOGNIZED IN NET INCOME

The Company recognized gains (losses) related to the effective portion of hedging relationships under the following categories:

For the millions of Canadian dollars	**2021**	Year ended December 31 2020
Operating revenues – regulated	**$ –**	$ (2)
Non-regulated fuel for generation and purchased power	**1**	–
Effective net gains (losses)	**$ 1**	$ (2)

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

REGULATORY ITEMS RECOGNIZED ON THE BALANCE SHEETS

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

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Derivative instrument assets (current and other assets)	**$ 237**	$ 14
Regulatory assets (current and other assets)	**23**	65
Derivative instrument liabilities (current and long-term liabilities)	**(20)**	(62)
Regulatory liabilities (current and long-term liabilities)	**(241)**	(15)
Net asset (liability)	**$ (1)**	$ 2

REGULATORY IMPACT RECOGNIZED IN NET INCOME

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

For the millions of Canadian dollars	**2021**	Year ended December 31 2020
Regulated fuel for generation and purchased power (1)	**$ 34**	$ (21)
Net gains (losses)	**$ 34**	$ (21)

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

HFT ITEMS RECOGNIZED ON THE BALANCE SHEETS

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

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Derivative instrument assets (current and other assets)	**$ 53**	$ 68
Derivative instrument liabilities (current and long-term liabilities)	**(662)**	(275)
Net derivative instrument liability	**$ (609)**	$ (207)

HFT ITEMS RECOGNIZED IN NET INCOME

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

For the millions of Canadian dollars	**2021**	Year ended December 31 2020
Non-regulated operating revenues	**$ (138)**	$ 204
Non-regulated fuel for generation and purchased power	**–**	(4)
Net gains (losses)	**$ (138)**	$ 200

OTHER DERIVATIVES RECOGNIZED ON THE BALANCE SHEETS

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

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Derivative instrument assets (current and other assets)	**$ 11**	$ 15
Derivative instrument liabilities (current and long-term liabilities)	**–**	(1)
Net derivative instrument assets	**$ 11**	$ 14

OTHER DERIVATIVES RECOGNIZED IN NET INCOME

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

For the millions of Canadian dollars		**2021**		Year ended December 31 2020
OM&G	**$**	**26**	$	(4)
Other income, net		**3**		13
Net gains	**$**	**29**	$	9

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, 2021 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, 2021, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Critical Accounting Estimates

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, 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.

Management has analyzed the impact of the COVID-19 pandemic on its estimates and assumptions and concluded that no material adjustments were required for the year ended December 31, 2021.

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

RATE REGULATION

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

The Company has recorded $2,566 million (2020 – $1,584 million) of regulatory assets and $2,055 million (2020 – $1,961 million) of regulatory liabilities as at December 31, 2021.

ACCUMULATED RESERVE – COST OF REMOVAL

Tampa Electric, PGS, NMGC and NSPI recognize non-asset retirement obligation ("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 property, plant and equipment 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. The balance of the Accumulated reserve – COR within regulatory liabilities was $819 million at December 31, 2021 (2020 – $865 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 9.2 years (9.0 years for 2021 benefit cost) for the Canadian plans and a weighted average of 11.1 years for the US plans). The Company's use of smoothed asset values reduces volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

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

	2021		2020	
	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	**2.38%**	**6.70%**	3.22%	7.00%
TECO Energy Group Supplemental Executive Retirement Plan (1)	**1.84%**	**N/A**	2.78%	N/A
TECO Energy Group Benefit Restoration Plan (1)	**1.71%**	**N/A**	2.81%	N/A
TECO Energy Post-retirement Health and Welfare Plan	**2.47%**	**N/A**	3.32%	N/A
New Mexico Gas Company Retiree Medical Plan	**2.49%**	**4.00%**	3.32%	3.25%
NSPI	**2.59%, 2.85%**	**5.25%**	3.13%, 3.21%	5.75%
GBPC Salaried	**4.25%**	**6.00%**	4.25%	6.00%
GBPC Union	**5.65%**	**5.65%**	5.00%	5.00%

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

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans was $85 million in 2021 (2020 – $87 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 2021 benefit cost of $1 million and $3 million respectively (2020 – $6 million and $5 million).

UNBILLED REVENUE

Electric and gas revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for other Emera utilities. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and determine related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses, inter-period changes to customer classes and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2021, unbilled revenues totalled $318 million (2020 – $286 million) on total regulated operating revenues of $5,926 million (2020 – $5,476 million).

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment represents 59 per cent of total assets on the Company's balance sheet. Included in "Property, plant and equipment" are the generation, transmission and distribution and other assets of the Company.

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

Depreciation expense was $877 million for the year ended December 31, 2021 (2020 – $860 million).

GOODWILL IMPAIRMENT ASSESSMENTS

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

If the Company performs the qualitative assessment 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 as a reduction to goodwill and a charge to operating expense. Significant assumptions used in estimating the fair value include discount and growth rates, rate case assumptions, valuation of the reporting units' net operating loss ("NOL"), utility sector market performance and transactions, projected operating and capital cash flows, and the fair value of debt. Adverse changes in assumptions could result in a future material impairment of the goodwill assigned to Emera's reporting units with goodwill. As part of the goodwill impairment assessment, management considered potential impacts of the COVID-19 pandemic on future earnings of the reporting units.

As of December 31, 2021, the Company had goodwill with a total carrying amount of $5,696 million (December 31, 2020 – $5,720 million). This goodwill represents the excess of the acquisition purchase price for TECO Energy (Tampa Electric, PGS and NMGC reporting units) and GBPC over the fair values assigned to identifiable assets acquired and liabilities assumed. The change in the carrying value of goodwill from 2020 to 2021 was a result of changes to the Canadian dollar on the goodwill balances.

As of December 31, 2021, $5.6 billion of Emera's goodwill was related to TECO Energy (Tampa Electric, PGS and NMGC reporting units). Qualitative assessments were performed for these reporting units given the significant excess of fair value over carrying amounts calculated during the last quantitative test in Q4 2019. Management concluded that it was more likely than not that the fair value of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required.

As of December 31, 2021, $68 million of Emera's goodwill was related to GBPC. In Q4 2021, the Company performed a quantitative impairment assessment for GBPC as this reporting unit is more sensitive to changes in assumptions due to limited excess of fair value over the carrying value. The assessment estimated that the fair value of the reporting unit exceeded its carrying value, including goodwill, by approximately 12 per cent. For further detail, refer to note 22 to the consolidated financial statements.

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.

Management considered whether the potential impacts of the COVID-19 pandemic on undiscounted future cash flows could indicate that long-lived assets are not recoverable. As at December 31, 2021, there were no indications of impairment of Emera's long-lived assets.

No impairment charges were recognized during the year ended December 31, 2021. In 2020, impairment charges of $25 million ($26 million after tax) were recognized on certain assets and recorded in "Impairment charge" on the Consolidated Income Statement.

INCOME TAXES

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

The Company believes the accounting 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 ("ARO")

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

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

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

As at December 31, 2021, AROs recorded on the balance sheet were $174 million (2020 – $178 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $422 million (2020 – $432 million), which will be incurred between 2022 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 policies that are applicable to, and adopted by the Company in 2021, are described as follows:

ACCOUNTING FOR CONVERTIBLE INSTRUMENTS AND CONTRACTS IN AN ENTITY'S OWN EQUITY

The Company adopted Accounting Standard Update ("ASU") 2020-06, *Debt – Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging – Contracts in Entity's Own Equity (Subtopic 815-40)* effective January 1, 2021 using the modified retrospective approach. The standard simplifies the accounting for convertible debenture debt instruments and convertible preferred stock, in addition to amending disclosure requirements. The standard also updates guidance for the derivative scope exception for contracts in an entity's own equity and the related earnings per share guidance. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

GUARANTEED DEBT SECURITIES DISCLOSURE REQUIREMENTS

The Company adopted ASU 2020-09, *Debt (Topic 470): Amendments to SEC Paragraphs pursuant to SEC Release No. 33-10762* effective December 31, 2021. The standard aligns with new SEC rules relating to changes to the disclosure requirements for certain registered debt securities that are guaranteed. The changes include simplifying and focusing the disclosure models, enhancing certain narrative disclosures and permitting the disclosures to be made outside of the financial statements. As a result of adopting this standard, the disclosures related to certain registered debt securities that are guaranteed were amended and removed from the consolidated financial statements and added to Management's Discussion & Analysis.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The ASUs that have been issued 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 consolidated financial statements.

Summary of Quarterly Results

For the quarter ended millions of Canadian dollars (except per share amounts)	**Q4 2021**	**Q3 2021**	**Q2 2021**	**Q1 2021**	Q4 2020	Q3 2020	Q2 2020	Q1 2020
Operating revenues	**$ 1,868**	**$ 1,148**	**$ 1,137**	**$ 1,612**	$ 1,537	$ 1,163	$ 1,169	$ 1,637
Net income attributable to common shareholders	**$ 324**	**$ (70)**	**$ (17)**	**$ 273**	$ 273	$ 84	$ 58	$ 523
Adjusted net income attributable to common shareholders	**$ 168**	**$ 175**	**$ 137**	**$ 243**	$ 188	$ 166	$ 118	$ 193
Earnings per common share – basic	**$ 1.24**	**$ (0.27)**	**$ (0.07)**	**$ 1.08**	$ 1.09	$ 0.34	$ 0.24	$ 2.14
Earnings per common share – diluted	**$ 1.20**	**$ (0.27)**	**$ (0.07)**	**$ 1.08**	$ 1.08	$ 0.34	$ 0.23	$ 2.13
Adjusted earnings per common share – basic	**$ 0.64**	**$ 0.68**	**$ 0.54**	**$ 0.96**	$ 0.75	$ 0.67	$ 0.48	$ 0.79

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.

Management Report

Management's Responsibility for Financial Reporting

The accompanying consolidated financial statements of Emera Incorporated and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The consolidated financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it considers most appropriate in the circumstances. In preparation of these consolidated financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management represents that such estimates, which have been properly reflected in the accompanying consolidated financial statements, are based on careful judgments and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the consolidated financial statements.

Emera Incorporated maintains effective systems of internal accounting and administrative controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is reliable and accurate, and that Emera Incorporated's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and its members are directors who are not officers or employees of Emera Incorporated. The Audit Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the consolidated financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards and with the standards of the Public Company Accounting Oversight Board. Ernst & Young LLP has full and free access to the Audit Committee.

February 14, 2022

"Scott Balfour"
President and Chief Executive Officer

"Gregory Blunden"
Chief Financial Officer

Independent Auditor's Report

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion

We have audited the consolidated financial statements of Emera Incorporated (the "Company"), which comprise the Consolidated Balance Sheets as at December 31, 2021 and 2020, and the Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2021 and 2020, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles ("USGAAP").

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period. These matters were addressed in the context of the audit of the consolidated financial statements as a whole, and in forming the auditor's opinion thereon, and we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

	Accounting for the effects of rate regulation
Key Audit Matter	As disclosed in note 7 of the consolidated financial statements, the Company has $2.6 billion in regulatory assets and $2.1 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including property, plant and equipment, operating revenues and expenses, income taxes, and depreciation expense. Auditing the impact of rate regulation on the Company's financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company's judgments include making an assessment of the probability of recovery of and recovery on costs incurred, of the disallowance of part of the cost of recently completed property, plant and equipment and construction work in progress, or of the probable refund to customers through future rates.

Accounting for the effects of rate regulation

How Our Audit Addressed the Key Audit Matter

We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, property, plant and equipment, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

Fair value measurement and disclosure of derivative financial instruments

Key Audit Matter

Held-for-trading ("HFT") derivative assets of $241 million and liabilities of $850 million, disclosed in note 15 to the consolidated financial statements, are measured at fair value. The Company recognized $138 million in realized and unrealized losses during the year with respect to HFT derivatives.

Auditing the Company's valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the fair value of the contracts. In determining the fair value of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials, the Company's own credit risk and discount rates. These assumptions have a significant impact on the fair value of the HFT derivatives.

How Our Audit Addressed the Key Audit Matter

We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company's valuation models and compared the commodity pricing curves, credit metrics and discount rates used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company's pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company's calculations to develop correlation factors and basis differentials. In addition, we assessed whether the fair value hierarchy disclosures in note 16 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the fair value of derivatives.

Other information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the consolidated financial statements and our auditor's reports thereon, in the Annual Report

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

The Annual Report is expected to be made available to us after the date of the auditor's report. If based on the work we will perform on this other information, we conclude there is a material misstatement of other information, we are required to report that fact to those charged with governance.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with USGAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Tracy Brennan.

Ernst & Young LLP

Chartered Professional Accountants

Halifax, Canada
February 14, 2022

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion on the Consolidated Financial Statements

We have audited the accompanying Consolidated Balance Sheets of Emera Incorporated (the "Company") as of December 31, 2021 and 2020, the related Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2021 and 2020, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2021, in conformity with United States generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for the effects of rate regulation

Description of the Matter

As disclosed in note 7 of the consolidated financial statements, the Company has $2.6 billion in regulatory assets and $2.1 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including property, plant and equipment, operating revenues and expenses, income taxes, and depreciation expense.

Auditing the impact of rate regulation on the Company's financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company's judgments include making an assessment of the probability of recovery of and recovery on costs incurred, of the disallowance of part of the cost of recently completed property, plant and equipment and construction work in progress, or of the probable refund to customers through future rates.

How We Addressed the Matter in Our Audit

We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, property, plant and equipment, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

Fair value measurement and disclosure of derivative financial instruments

Description of the Matter

Held-for-trading ("HFT") derivative assets of $241 million and liabilities of $850 million, disclosed in note 15 to the consolidated financial statements, are measured at fair value. The Company recognized $138 million in realized and unrealized losses during the year with respect to HFT derivatives.

Auditing the Company's valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the fair value of the contracts. In determining the fair value of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials, the Company's own credit risk and discount rates. These assumptions have a significant impact on the fair value of the HFT derivatives.

How We Addressed the Matter in Our Audit

We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company's valuation models and compared the commodity pricing curves, credit metrics and discount rates used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company's pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company's calculations to develop correlation factors and basis differentials. In addition, we assessed whether the fair value hierarchy disclosures in note 16 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the fair value of derivatives.

Ernst + Young LLP

Chartered Professional Accountants

We have served as the Company's auditor since 1998.

Halifax, Canada
February 14, 2022

Emera Incorporated

Consolidated Statements of Income

For the millions of Canadian dollars (except per share amounts)	Year ended December 31 **2021**	 2020
Operating revenues		
Regulated electric	**$ 4,665**	$ 4,442
Regulated gas	**1,261**	1,034
Non-regulated	**(161)**	30
Total operating revenues (note 6)	**5,765**	5,506
Operating expenses		
Regulated fuel for generation and purchased power (notes 17 and 19)	**1,763**	1,420
Regulated cost of natural gas	**472**	293
Non-regulated fuel for generation and purchased power	**(1)**	4
Operating, maintenance and general	**1,369**	1,419
Provincial, state, and municipal taxes	**330**	317
Depreciation and amortization	**902**	881
Impairment charges	**–**	25
Total operating expenses	**4,835**	4,359
Income from operations	**930**	1,147
Income from equity investments (note 8)	**143**	149
Other income, net (note 9)	**93**	708
Interest expense, net	**611**	679
Income before provision for income taxes	**555**	1,325
Income tax (recovery) expense (note 10)	**(6)**	341
Net income	**561**	984
Non-controlling interest in subsidiaries	**1**	1
Preferred stock dividends	**50**	45
Net income attributable to common shareholders	**$ 510**	$ 938
Weighted average shares of common stock outstanding (in millions) (note 12)		
Basic	**257**	248
Diluted	**258**	248
Earnings per common share (note 12)		
Basic	**$ 1.98**	$ 3.78
Diluted	**$ 1.98**	$ 3.78
Dividends per common share declared	**$ 2.5750**	$ 2.4750

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated

Consolidated Statements of Comprehensive Income

For the millions of Canadian dollars	Year ended December 31 2021	 2020
Net income	**$ 561**	$ 984
Other comprehensive income (loss), net of tax		
Foreign currency translation adjustment (1)	**(42)**	(201)
Unrealized gains on net investment hedges (2) (3)	**5**	26
Cash flow hedges		
Net derivative gains (4)	**18**	–
Less: reclassification adjustment for (gains) losses included in income	**(1)**	2
Net effects of cash flow hedges	**17**	2
Net change in unrecognized pension and post-retirement benefit obligation (5)	**124**	(1)
Other comprehensive income (loss) (6)	**104**	(174)
Comprehensive income	**665**	810
Comprehensive income attributable to non-controlling interest	**1**	1
Comprehensive Income of Emera Incorporated	**$ 664**	$ 809

The accompanying notes are an integral part of these consolidated financial statements.

(1) Net of tax expense of $5 million (2020 – $1 million recovery) for the year ended December 31, 2021.
(2) The Company has designated $1.2 billion United States dollar denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations.
(3) Net of tax expense of $1 million (2020 – $4 million expense) for the year ended December 31, 2021.
(4) Net of tax expense of $6 million (2020 – nil) for the year ended December 31, 2021.
(5) Net of tax expense of $2 million (2020 – $1 million recovery) for the year ended December 31, 2021.
(6) Net of tax expense of $14 million (2020 – $2 million expense) for the year ended December 31, 2021.

Emera Incorporated

Consolidated Balance Sheets

As at millions of Canadian dollars	December 31 2021	December 31 2020
Assets		
Current assets		
Cash and cash equivalents	**$ 394**	$ 220
Restricted cash (note 32)	**23**	34
Inventory (note 14)	**538**	453
Derivative instruments (notes 15 and 16)	**195**	73
Regulatory assets (note 7)	**253**	165
Receivables and other current assets (note 18)	**1,733**	1,233
	3,136	2,178
Property, plant and equipment, net of accumulated depreciation and amortization of $8,739 and $8,714, respectively (note 20)	**20,353**	19,535
Other assets		
Deferred income taxes (note 10)	**295**	209
Derivative instruments (notes 15 and 16)	**106**	25
Regulatory assets (note 7)	**2,313**	1,419
Net investment in direct financing lease (note 19)	**462**	475
Investments subject to significant influence (note 8)	**1,382**	1,346
Goodwill (note 22)	**5,696**	5,720
Other long-term assets	**501**	327
	10,755	9,521
Total assets	**$ 34,244**	$ 31,234

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated

Consolidated Balance Sheets (continued)

As at millions of Canadian dollars		**December 31 2021**		December 31 2020
Liabilities and Equity				
Current liabilities				
Short-term debt (note 23)	**$**	**1,742**	$	1,625
Current portion of long-term debt (note 25)		**462**		1,382
Accounts payable		**1,485**		1,148
Derivative instruments (notes 15 and 16)		**533**		251
Regulatory liabilities (note 7)		**290**		129
Other current liabilities (note 24)		**366**		340
		4,878		4,875
Long-term liabilities				
Long-term debt (note 25)		**14,196**		12,339
Deferred income taxes (note 10)		**1,868**		1,629
Derivative instruments (notes 15 and 16)		**149**		87
Regulatory liabilities (note 7)		**1,765**		1,832
Pension and post-retirement liabilities (note 21)		**370**		453
Other long-term liabilities (notes 8 and 26)		**868**		781
		19,216		17,121
Equity				
Common stock (note 11)		**7,242**		6,705
Cumulative preferred stock (note 28)		**1,422**		1,004
Contributed surplus		**79**		79
Accumulated other comprehensive income (loss) (note 13)		**25**		(79)
Retained earnings		**1,348**		1,495
Total Emera Incorporated equity		**10,116**		9,204
Non-controlling interest in subsidiaries (note 29)		**34**		34
Total equity		**10,150**		9,238
Total liabilities and equity	**$**	**34,244**	$	31,234

Commitments and contingencies (note 27)

The accompanying notes are an integral part of these consolidated financial statements.

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard"
Chair of the Board

"Scott Balfour"
President and Chief Executive Officer

Emera Incorporated

Consolidated Statements of Cash Flows

For the millions of Canadian dollars	Year ended December 31 **2021**	 2020
Operating activities		
Net income	**$ 561**	$ 984
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**915**	899
Income from equity investments, net of dividends	**(69)**	(76)
Allowance for equity funds used during construction	**(61)**	(45)
Deferred income taxes, net	**(37)**	381
Net change in pension and post-retirement liabilities	**(23)**	(23)
Regulated fuel adjustment mechanism	**(166)**	(94)
Net change in fair value of derivative instruments	**404**	(36)
Net change in regulatory assets and liabilities	**(176)**	(87)
Net change in capitalized transportation capacity	**(107)**	52
Impairment charges	**–**	25
Gain on sale, excluding transaction costs	**–**	(603)
Other operating activities, net	**96**	43
Changes in non-cash working capital (note 30)	**(152)**	217
Net cash provided by operating activities	**1,185**	1,637
Investing activities		
Additions to property, plant and equipment	**(2,359)**	(2,623)
Proceeds from dispositions (note 4)	**3**	1,401
Other investing activities	**24**	(2)
Net cash used in investing activities	**(2,332)**	(1,224)
Financing activities		
Change in short-term debt, net	**(155)**	385
Proceeds from short-term debt with maturities greater than 90 days	**640**	399
Repayment of short-term debt with maturities greater than 90 days	**(377)**	(688)
Proceeds from long-term debt, net of issuance costs	**2,554**	428
Retirement of long-term debt	**(1,660)**	(513)
Net proceeds (repayments) under committed credit facilities	**82**	(203)
Issuance of common stock, net of issuance costs	**317**	285
Issuance of preferred stock, net of issuance costs (note 28)	**416**	–
Dividends on common stock	**(443)**	(409)
Dividends on preferred stock	**(50)**	(45)
Other financing activities	**(13)**	(11)
Net cash provided by (used in) financing activities	**1,311**	(372)
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**(1)**	(61)
Net increase (decrease) in cash, cash equivalents, restricted cash	**163**	(20)
Cash, cash equivalents, and restricted cash, beginning of year	**254**	274
Cash, cash equivalents, and restricted cash, end of year	**$ 417**	$ 254
Cash, cash equivalents and restricted cash consists of:		
Cash	**$ 237**	$ 220
Short-term investments	**157**	–
Restricted cash	**23**	34
Cash, cash equivalents and restricted cash	**$ 417**	$ 254

Supplementary Information to Consolidated Statements of Cash Flows (note 30)

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated

Consolidated Statements of Changes in Equity

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss) (1)	Retained Earnings	Non-Controlling Interest	Total Equity
Balance, December 31, 2020	**$ 6,705**	**$ 1,004**	**$ 79**	**$ (79)**	**$ 1,495**	**$ 34**	**$ 9,238**
Net income of Emera incorporated	**–**	**–**	**–**	**–**	**560**	**1**	**561**
Other comprehensive income, net of tax expense of $14 million	**–**	**–**	**–**	**104**	**–**	**–**	**104**
Dividends declared on preferred stock (note 28)	**–**	**–**	**–**	**–**	**(50)**	**–**	**(50)**
Dividends declared on common stock ($2.5750/share)	**–**	**–**	**–**	**–**	**(657)**	**–**	**(657)**
Issuance of preferred shares, net of after-tax issuance costs (note 28)	**–**	**418**	**–**	**–**	**–**	**–**	**418**
Common stock issued under purchase plan	**235**	**–**	**–**	**–**	**–**	**–**	**235**
Issuance of common stock, net of after-tax issuance costs	**284**	**–**	**–**	**–**	**–**	**–**	**284**
Senior management stock options exercised	**14**	**–**	**–**	**–**	**–**	**–**	**14**
Other	**4**	**–**	**–**	**–**	**–**	**(1)**	**3**
Balance, December 31, 2021	**$ 7,242**	**$ 1,422**	**$ 79**	**$ 25**	**$ 1,348**	**$ 34**	**$ 10,150**
Balance, December 31, 2019	$ 6,216	$ 1,004	$ 78	$ 95	$ 1,173	$ 35	$ 8,601
Net income of Emera Inc	–	–	–	–	983	1	984
Other comprehensive loss, net of tax expense of $2 million	–	–	–	(174)	–	–	(174)
Dividends declared on preferred stock (note 28)	–	–	–	–	(45)	–	(45)
Dividends declared on common stock ($2.4750/share)	–	–	–	–	(609)	–	(609)
Common stock issued under purchase plan	215	–	–	–	–	–	215
Issuance of common stock, net of after-tax issuance costs	251	–	–	–	–	–	251
Senior management stock options exercised	20	–	(1)	–	–	–	19
Adoption of credit losses accounting standard	–	–	–	–	(7)	–	(7)
Other	3	–	2	–	–	(2)	3
Balance, December 31, 2020	$ 6,705	$ 1,004	$ 79	$ (79)	$ 1,495	$ 34	$ 9,238

(1) Accumulated Other Comprehensive Income (Loss) (“AOCI”) (“AOCL”)

The accompanying notes are an integral part of these consolidated financial statements.

Notes to the Consolidated Financial Statements

As at December 31, 2021 and 2020

1. Summary of Significant Accounting Policies

NATURE OF OPERATIONS

Emera Incorporated ("Emera" or the "Company") is an energy and services company which invests in electricity generation, transmission and distribution, and gas transmission and distribution.

At December 31, 2021, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric, a vertically integrated regulated electric utility, serving approximately 810,600 customers in West Central Florida;
- Canadian Electric Utilities, which includes:
  - Nova Scotia Power Inc. ("NSPI"), a vertically integrated regulated electric utility and the primary electricity supplier in Nova Scotia, serving approximately 536,000 customers; and
  - Emera Newfoundland & Labrador Holdings Inc. ("ENL"), consisting of two transmission investments related to an 824 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador being developed by Nalcor Energy. ENL's two investments are:
    - a 100 per cent investment in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.8 billion (including AFUDC) transmission project, including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. This project went in service on January 15, 2018; and
    - a 37.4 per cent investment in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.7 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Construction of the LIL has been completed and Nalcor recognized the first flow of energy from Labrador to Newfoundland in June 2018. Muskrat Falls generators are completed and available for service and Nalcor is forecasting it will achieve final commissioning of Muskrat Falls and LIL in the first half of 2022. For further details, refer to note 27.
- Other Electric Utilities, which includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities that include:
  - The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated regulated electric utility on the island of Barbados, serving approximately 132,000 customers;
  - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated regulated electric utility on Grand Bahama Island, serving approximately 19,000 customers;
  - a 51.9 per cent interest in Dominica Electricity Services Ltd. ("Domlec"), a vertically integrated regulated electric utility on the island of Dominica, serving approximately 35,700 customers; and
  - a 19.5 per cent equity interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.

On March 24, 2020, Emera completed the sale of Emera Maine which was previously included in the Other Electric Utilities segment. Refer to note 4.

- Gas Utilities and Infrastructure, which includes:
  - Peoples Gas System ("PGS"), a regulated gas distribution utility, serving approximately 445,000 customers across Florida;
  - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 542,000 customers in New Mexico;
  - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida;
  - Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas ("LNG") from Saint John, New Brunswick to the United States border under a 25-year firm service agreement with Repsol Energy Canada, which expires in 2034; and
  - a 12.9 per cent interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline, that transports natural gas throughout markets in Atlantic Canada and the northeastern United States.
- Emera's other reportable segment includes investments in energy-related non-regulated companies which includes:
  - Emera Energy, which consists of:
    - Emera Energy Services ("EES"), a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services;
    - Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; and
    - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 633 MW pumped storage hydroelectric facility in northwestern Massachusetts.
  - Emera Reinsurance Limited, a captive insurance company providing insurance and reinsurance to Emera and certain affiliates;
  - Emera US Finance LP ("Emera Finance") and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
  - Emera Technologies LLC, a wholly owned technology company focused on finding ways to deliver renewables and resilient energy to customers;
  - Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States; and
  - Other investments.

In 2020, the outbreak of COVID-19, resulted in governments worldwide enacting emergency measures to combat the spread of the virus. Management considered the impact of COVID-19 in the Company's estimates and results and concluded the financial statements as of and for the year ended December 31, 2021 were not materially impacted.

BASIS OF PRESENTATION

These consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP"). In the opinion of management, these consolidated financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera.

All dollar amounts are presented in Canadian dollars, unless otherwise indicated.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements of Emera include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity ("VIE") in which Emera is the primary beneficiary. For further details on VIEs, refer to note 32. Emera uses the equity method of accounting to record investments in which the Company has the ability to exercise significant influence, and for VIEs in which Emera is not the primary beneficiary.

The Company performs ongoing analysis to assess whether it holds any VIEs or whether any reconsideration events have arisen with respect to existing VIEs. To identify potential VIEs, management reviews contractual and ownership arrangements such as leases, long-term purchase power agreements, tolling contracts, guarantees, jointly owned facilities and equity investments. VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impacts its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where Emera has an investment in a VIE but is not deemed the primary beneficiary, the VIE is accounted for using the equity method.

Intercompany balances and transactions have been eliminated on consolidation, except for the net profit on certain transactions between certain non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues. An offset is recorded to property, plant and equipment, regulatory assets, regulated fuel for generation and purchased power, or operating, maintenance and general ("OM&G"), depending on the nature of the transaction.

USE OF MANAGEMENT ESTIMATES

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, 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.

Management has analyzed the impact of the COVID-19 pandemic on its estimates and assumptions and concluded that no material adjustments were required for the year ended December 31, 2021.

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

REGULATORY MATTERS

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. The rates are designed to recover prudently incurred costs of providing the regulated products or services and provide an opportunity for a reasonable rate of return on invested capital, as applicable. For further detail, refer to note 7.

FOREIGN CURRENCY TRANSLATION

Monetary assets and liabilities denominated in foreign currencies are converted to Canadian dollars at the rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are included in income.

Assets and liabilities of foreign operations whose functional currency is not the Canadian dollar are translated using the exchange rates in effect at the balance sheet date and the results of operations at the average exchange rate in effect for the period. The resulting exchange gains and losses on the assets and liabilities are deferred on the balance sheet in AOCI.

The Company designates certain United States dollar denominated debt held in Canadian dollar functional currency companies as hedges of net investments in United States dollar denominated foreign operations. The change in the carrying amount of these investments, measured at the exchange rates in effect at the balance sheet date is recorded in Other Comprehensive Income ("OCI").

REVENUE RECOGNITION

Regulated Electric Revenue

Electric revenues, including energy charges, demand charges, basic facilities charges and clauses and riders, are recognized when obligations under the terms of a contract are satisfied, which is when electricity is delivered to customers over time as the customer simultaneously receives and consumes the benefits of the electricity. Electric revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity are recognized at rates approved by the respective regulator and recorded based on metered usage, which occurs on a periodic, systematic basis, generally monthly or bi-monthly. At the end of each reporting period, the electricity delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the number of megawatt hours ("MWh") delivered to customers at the established rates expected to prevail in the upcoming billing cycle. This estimate includes assumptions as to the pattern of energy demand, weather, line losses and inter-period changes to customer classes.

Regulated Gas Revenue

Gas revenues, including energy charges, demand charges, basic facilities charges and applicable clauses and riders, are recognized when obligations under the terms of a contract are satisfied, which is when gas is delivered to customers over time as the customer simultaneously receives and consumes the benefits of the gas. Gas revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the distribution and sale of gas are recognized at rates approved by the respective regulator and recorded based on metered usage, which occurs on a periodic, systematic basis, generally monthly. At the end of each reporting period, the gas delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the number of therms delivered to customers at the established rates expected to prevail in the upcoming billing cycle. This estimate includes assumptions as to the pattern of usage, weather, and inter-period changes to customer classes.

Non-regulated Revenue

Marketing and trading margins are comprised of Emera Energy's corresponding purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management revenues. Revenues are recorded when obligations under terms of a contract are satisfied and are presented on a net basis, reflecting the nature of the contractual relationships with customers and suppliers.

Energy sales are recognized when obligations under the terms of the contracts are satisfied, which is when electricity is delivered to customers over time.

Other non-regulated revenues are recorded when obligations under terms of a contract are satisfied.

Other

Sales, value add, and other taxes, except for gross receipts taxes discussed below, collected by the Company concurrent with revenue-producing activities are excluded from revenue.

LEASES

The Company determines whether a contract contains a lease at inception by evaluating if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

Emera has leases with independent power producers ("IPP") and other utilities with annual requirements to purchase wind and hydro energy over varying contract lengths that are classified as finance leases. These finance leases are not recorded on the Company's Consolidated Balance Sheets as payments associated with the leases are variable in nature and there are no minimum fixed lease payments. Lease expense associated with these leases is recorded as "Regulated fuel for generation and purchased power" on the Consolidated Statements of Income.

Operating lease liabilities and right-of-use ("ROU") assets are recognized on the Consolidated Balance Sheets based on the present value of the future minimum lease payments over the lease term at commencement date. As most of Emera's leases do not provide an implicit rate, the incremental borrowing rate at commencement of the lease is used in determining the present value of future lease payments. Lease expense is recognized on a straight-line basis over the lease term and is recorded as "Operating, maintenance and general" on the Consolidated Statements of Income.

Where the Company is the lessor, a lease is a sales-type lease if certain criteria are met and the arrangement transfers control of the underlying asset to the lessee. For arrangements where the criteria are met due to the presence of a third-party residual value guarantee, the lease is a direct financing lease.

For direct finance leases, a net investment in the lease is recorded that consists of the sum of the minimum lease payments and residual value (net of estimated executory costs and unearned income). The difference between the gross investment and the cost of the leased item is recorded as unearned income at the inception of the lease. Unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

For sales-type leases, the accounting is similar to the accounting for direct finance leases, however the difference between the fair value and the carrying value of the leased item is recorded at lease commencement rather than deferred over the term of the lease.

Emera has certain contractual agreements that include lease and non-lease components, which management has elected to account for as a single lease component.

FRANCHISE FEES AND GROSS RECEIPTS

Tampa Electric and PGS recover from customers certain costs incurred, on a dollar-for-dollar basis, through prices approved by the Florida Public Service Commission ("FPSC"). The amounts included in customers' bills for franchise fees and gross receipt taxes are included as "Regulated electric" and "Regulated gas" revenues in the Consolidated Statements of Income. Franchise fees and gross receipt taxes payable by Tampa Electric and PGS are included as an expense on the Consolidated Statements of Income in "Provincial, state and municipal taxes".

NMGC is an agent in the collection and payment of franchise fees and gross receipt taxes and is not required by a tariff to present the amounts on a gross basis. Therefore, NMGC's franchise fees and gross receipt taxes are presented net with no line item impact on the Consolidated Statements of Income.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at original cost, including allowance for funds used during construction ("AFUDC") or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units of property, plant and equipment, are included in "Property, plant and equipment". When units of regulated property, plant and equipment are replaced, renewed or retired, their cost plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income. Where a disposition of non-regulated property, plant and equipment occurs, gains and losses are included in income as the dispositions occur.

The cost of property, plant and equipment represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, asset retirement obligations ("ARO"), and overhead attributable to the capital project. Overhead includes corporate costs such as finance, information technology and labour costs, along with other costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance. Expenditures for project development are capitalized if they are expected to have a future economic benefit.

Normal maintenance projects are expensed as incurred. Planned major maintenance projects that do not increase the overall life of the related assets are expensed. When a major maintenance project increases the life or value of the underlying asset, the cost is capitalized.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each functional class of depreciable property. For some of Emera's rate-regulated subsidiaries, depreciation is calculated using the group remaining life method, which is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property. The service lives of regulated assets require the appropriate regulatory approval.

Intangible assets, which are included in "Property, plant and equipment," consist primarily of computer software and land rights. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the asset in each category. For some of Emera's rate-regulated subsidiaries, amortization is calculated using the amortizable life method which is applied to the net book value to date over the remaining life of those assets. The service lives of regulated intangible assets require regulatory approval.

GOODWILL

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. For further detail, refer to note 22.

INCOME TAXES AND INVESTMENT TAX CREDITS

Emera recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the Consolidated Balance Sheets, and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period when the change is enacted, unless required to be offset to a regulatory asset or liability by law or by order of the regulator. Emera recognizes the effect of income tax positions only when it is more likely than not that they will be realized. Management reviews all readily available current and historical information, including forward-looking information, and the likelihood that deferred tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of deferred tax assets and liabilities are made. If management subsequently determines that it is likely that some or all of a deferred income tax asset will not be realized, then a valuation allowance is recorded to reflect the amount of deferred income tax asset expected to be realized.

Generally, investment tax credits are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not. Investment tax credits earned by Tampa Electric, PGS and NMGC on regulated assets are deferred and amortized over the estimated service lives of the related properties, as required by regulatory practices.

Tampa Electric, PGS, NMGC, BLPC and Domlec collect income taxes from customers based on current and deferred income taxes. NSPI, ENL and Brunswick Pipeline collect income taxes from customers based on income tax that is currently payable except for the deferred income taxes on certain regulatory balances specifically prescribed by the regulator. For the balance of regulated deferred income taxes, NSPI, ENL and Brunswick Pipeline recognize regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future years. These regulated assets or liabilities are grossed up using the respective income tax rate to reflect the income tax associated with future revenues that are required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets. GBPC is not subject to income taxes.

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively. For further information, refer to note 10.

DERIVATIVES AND HEDGING ACTIVITIES

The Company manages its exposure to normal operating and market risks relating to commodity prices, foreign exchange, interest rates and share prices through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of foreign exchange forwards and swaps, interest rate options and swaps, equity derivatives, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. 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 and PGS have no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases which ends 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.

Emera classifies gains and losses on derivatives as a component of fuel for generation and purchased power, other expenses, inventory, OM&G and property, plant and equipment, depending on the nature of the item being economically hedged. Transportation capacity arising as a result of marketing and trading derivative transactions is recognized as an asset in "Receivables and other current assets" and amortized over the period of the transportation contract term. Cash flows from derivative activities are presented in the same category as the item being hedged within operating or investing activities on the Consolidated Statements of Cash Flows. Non-hedged derivatives are included in operating cash flows on the Consolidated Statements of Cash Flows.

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables and other current assets" and obligations to return cash collateral are recognized in "Accounts payable".

CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition.

RECEIVABLES AND ALLOWANCE FOR CREDIT LOSSES

Utility customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity and gas sales are approximately 30 days. A late payment fee may be assessed on account balances after the due date.

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit assessments may be conducted on new customers. Deposits are requested on accounts in accordance with the Company's policy. The Company also maintains provisions for expected credit losses, which are assessed on a regular basis.

Management estimates credit losses related to accounts receivable after considering historical loss experience, customer deposits, current events, the characteristics of existing accounts and reasonable and supportable forecasts that affect the collectability of the reported amount. Provisions for credit losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

The economic impact of COVID-19 in the service territories in which Emera operates, has impacted the aging of customer receivables resulting in higher allowances for credit losses related to customer receivables, however it has not had a material impact on earnings.

INVENTORY

Fuel and materials inventories are valued using the weighted-average cost method. These inventories are carried at the lower of weighted-average cost or net realizable value, unless evidence indicates that the weighted-average cost will be recovered in future customer rates.

ASSET IMPAIRMENT

Long-Lived Assets

Emera 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 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'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. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

Management considered whether the potential impacts of the COVID-19 pandemic on undiscounted future cash flows could indicate that long-lived assets are not recoverable. As at December 31, 2021, there are no indications of impairment of Emera's long-lived assets.

No impairment charges were recognized during the year ended December 31, 2021. In 2020, impairment charges of $25 million ($26 million after tax) were recognized on certain assets and recorded in "Impairment charges" in the Consolidated Statements of Income.

Goodwill

Goodwill is not amortized but is subject to an annual assessment for impairment at the reporting unit level with interim impairment tests performed when impairment indicators are present. Reporting units are generally determined at the operating segment level or one level below the operating segment level. Reporting units with similar characteristics are grouped for the purpose of determining impairment, if any, of goodwill. 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 as a reduction to goodwill and a charge to operating expense. Management estimates the fair value of the reporting unit by using the income approach, or a combination of the income and market approach. The income approach is applied using a discounted cash flow analysis which relies on management's best estimate of the reporting units' projected cash flows. The analysis includes an estimate of terminal values based on these expected cash flows using a methodology which derives a valuation using an assumed perpetual annuity based on the reporting unit's residual cash flows. The discount rate used is a market participant rate based on a peer group of publicly traded comparable companies and represents the weighted average cost of capital of comparable companies. When using the market approach, management estimates fair value based on comparable companies and transactions within the utility industry. Significant assumptions used in estimating the fair value include discount and growth rates, rate case assumptions, valuation of the reporting units' net operating loss ("NOL"), utility sector market performance and transactions, projected operating and capital cash flows and the fair value of debt. Adverse changes in assumptions described above could result in a future material impairment of the goodwill assigned to Emera's reporting units with goodwill. As part of the goodwill impairment assessment management considered the potential impacts of the COVID-19 pandemic on the future earnings of the reporting units.

As of December 31, 2021, $5.6 billion of Emera's goodwill was related to TECO Energy (Tampa Electric, PGS and NMGC reporting units). Qualitative assessments were performed for these reporting units given the significant excess of fair value over carrying amounts calculated during the last quantitative test in Q4 2019. Management concluded 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.

As of December 31, 2021, $68 million of Emera's goodwill was related to GBPC. In Q4 2021, the Company performed a quantitative impairment assessment for GBPC as this reporting unit is more sensitive to changes in assumptions due to limited excess of fair value over the carrying value. The assessment estimated that the fair value of the reporting unit exceeded its carrying value, including goodwill, by approximately 12 per cent. For further detail, refer to note 22.

Equity Method Investments

The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the fair value of these investments to their carrying values, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators, including the impact of COVID-19. If an impairment exists, and it is determined to be other-than-temporary, a charge is recognized in earnings equal to the amount the carrying value exceeds the investment's fair value. No impairment of equity method investments was required in either 2021 or 2020.

Financial Assets

Equity investments, other than those accounted for under the equity method of accounting, are measured at fair value, with changes in fair value recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable fair values are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investments. No impairment of financial assets was required in either 2021 or 2020.

ASSET RETIREMENT OBLIGATIONS

An ARO is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

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. AROs are included in "Other long-term liabilities" and accretion expense is included as part of "Depreciation and amortization". Any regulated accretion expense not yet approved by the regulator is recorded in "Property, plant and equipment" and included in the next depreciation study.

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 in the period in which an amount can be determined.

COST OF REMOVAL

Tampa Electric, PGS, NMGC and NSPI recognize non-ARO costs of removal ("COR") as regulatory liabilities. The non-ARO COR represent funds received from customers through depreciation rates to cover estimated future non-legally required COR of property, plant and equipment upon retirement. 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.

STOCK-BASED COMPENSATION

The Company has several stock-based compensation plans: a common share option plan for senior management; an employee common share purchase plan; a deferred share unit ("DSU") plan; a performance share unit ("PSU") plan; and a restricted share unit ("RSU") plan. The Company accounts for its plans in accordance with the fair value based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period using the graded vesting method. Stock-based compensation plans recognized as liabilities are initially measured at fair value and re-measured at fair value at each reporting date, with the change in liability recognized in income.

EMPLOYEE BENEFITS

The costs of the Company's pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCI or regulatory assets. The components of net periodic benefit cost other than the service cost component are included in "Other income, net" on the Consolidated Statements of Income.

2. Change in Accounting Policy

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2021, are described as follows:

ACCOUNTING FOR CONVERTIBLE INSTRUMENTS AND CONTRACTS IN AN ENTITY'S OWN EQUITY

The Company adopted Accounting Standard Update ("ASU") 2020-06, *Debt – Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging – Contracts in Entity's Own Equity (Subtopic 815-40)* effective January 1, 2021 using the modified retrospective approach. The standard simplifies the accounting for convertible debenture debt instruments and convertible preferred stock, in addition to amending disclosure requirements. The standard also updates guidance for the derivative scope exception for contracts in an entity's own equity and the related earnings per share guidance. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

GUARANTEED DEBT SECURITIES DISCLOSURE REQUIREMENTS

The Company adopted ASU 2020-09, *Debt (Topic 470): Amendments to SEC Paragraphs pursuant to SEC Release No. 33-10762* effective December 31, 2021. The standard aligns with new SEC rules relating to changes to the disclosure requirements for certain registered debt securities that are guaranteed. The changes include simplifying and focusing the disclosure models, enhancing certain narrative disclosures and permitting the disclosures to be made outside of the financial statements. As a result of adopting this standard, the disclosures related to certain registered debt securities that are guaranteed were amended and removed from the consolidated financial statements and added to Management's Discussion & Analysis.

3. Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The ASUs that have been issued 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 consolidated financial statements.

4. Dispositions

On March 24, 2020, Emera completed the sale of Emera Maine for a total enterprise value of approximately $2.0 billion including cash proceeds of $1.4 billion, transferred debt and working capital adjustments. A gain on disposition of $585 million ($309 million after tax) net of transaction costs, was recognized in the Other segment and included in "Other income" on the Consolidated Statements of Income.

5. Segment Information

Emera manages its reportable segments separately due in part to their different operating, regulatory and geographical environments. Segments are reported based on each subsidiary's contribution of revenues, net income attributable to common shareholders and total assets, as reported to the Company's chief operating decision maker. Emera's five reportable segments are Florida Electric Utility, Canadian Electric Utilities, Other Electric Utilities, Gas Utilities and Infrastructure, and Other.

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter-segment Eliminations	Total
For the year ended December 31, 2021							
Operating revenues from external customers [1]	$ 2,718	$ 1,501	$ 445	$ 1,276	$ (175)	$ –	$ 5,765
Inter-segment revenues [1]	6	–	–	4	18	(28)	–
Total operating revenues	2,724	1,501	445	1,280	(157)	(28)	5,765
Regulated fuel for generation and purchased power	894	654	218	–	–	(3)	1,763
Regulated cost of natural gas	–	–	–	472	–	–	472
OM&G	536	291	140	325	93	(16)	1,369
Depreciation and amortization	469	246	58	121	8	–	902
Income from equity investments	–	103	4	20	16	–	143
AFUDC – debt and equity	77	8	–	7	–	–	92
Interest expense, net	138	132	21	51	269	–	611
Internally allocated interest [2]	–	–	–	13	(13)	–	–
Income tax expense (recovery)	72	9	1	62	(150)	–	(6)
Net income (loss) attributable to common shareholders	462	241	21	198	(412)	–	510
Capital expenditures	1,331	366	111	515	5	–	2,328
As at December 31, 2021							
Total assets	17,903	7,418	1,402	6,666	2,034	(1,179)[3]	34,244
Investments subject to significant influence	–	1,215	44	123	–	–	1,382
Goodwill	4,436	–	68	1,189	3	–	5,696

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.
(2) Segment net income is reported on a basis that includes internally allocated financing costs.
(3) Primarily relates to consolidated deferred tax reclassifications. Deferred tax assets are reclassified and netted with deferred tax liabilities upon consolidation.

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter-segment Eliminations	Total
For the year ended December 31, 2020							
Operating revenues from external customers (1)	$ 2,473	$ 1,494	$ 474	$ 1,051	$ 14	$ –	$ 5,506
Inter-segment revenues (1)	7	–	–	7	15	(29)	–
Total operating revenues	2,480	1,494	474	1,058	29	(29)	5,506
Regulated fuel for generation and purchased power	574	659	194	–	–	(7)	1,420
Regulated cost of natural gas	–	–	–	293	–	–	293
OM&G	552	282	151	334	115	(15)	1,419
Depreciation and amortization	455	236	71	111	8	–	881
Income from equity investments	–	96	4	20	29	–	149
AFUDC – debt and equity	54	4	1	9	–	–	68
Interest expense, net	151	139	32	56	301	–	679
Internally allocated interest (2)	–	–	–	13	(13)	–	–
Gain on sale, net of transactions costs	–	–	–	–	585	–	585
Impairment charges	–	–	–	–	(25)	–	(25)
Income tax expense (recovery)	89	17	(8)	51	192	–	341
Net income attributable to common shareholders	501	221	35	162	19	–	938
Capital expenditures	1,361	338	148	749	4	–	2,600
As at December 31, 2020							
Total assets	16,889	6,752	1,365	6,067	1,234	(1,073)(3)	31,234
Investments subject to significant influence	–	1,176	41	129	–	–	1,346
Goodwill	4,455	–	68	1,194	3	–	5,720

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.

(2) Segment net income is reported on a basis that includes internally allocated financing costs.

(3) Primarily relates to consolidated deferred tax reclassifications. Deferred tax assets are reclassified and netted with deferred tax liabilities upon consolidation.

GEOGRAPHICAL INFORMATION

Revenues (based on country of origin of the product or service sold)

For the millions of Canadian dollars	Year ended December 31 **2021**	2020
United States	**$ 3,754**	$ 3,522
Canada	**1,566**	1,569
Barbados	**292**	263
The Bahamas	**110**	112
Dominica	**43**	40
	$ 5,765	$ 5,506

Property Plant and Equipment:

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
United States	**$ 14,978**	$ 14,353
Canada	**4,440**	4,304
Barbados	**535**	510
The Bahamas	**322**	289
Dominica	**78**	79
	$ 20,353	$ 19,535

6. Revenue

The following disaggregates the Company's revenue by major source:

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter-segment Eliminations	Total
For the year ended December 31, 2021							
Regulated Electric Revenue							
Residential	$ 1,449	$ 797	$ 165	$ –	$ –	$ –	$ 2,411
Commercial	754	407	232	–	–	–	1,393
Industrial	215	237	26	–	–	–	478
Other electric and regulatory deferrals	289	27	7	–	–	–	323
Other (1)	17	33	15	1	–	(6)	60
Regulated electric revenue	2,724	1,501	445	1	–	(6)	4,665
Regulated Gas Revenue							
Residential	–	–	–	642	–	–	642
Commercial	–	–	–	379	–	–	379
Industrial	–	–	–	65	–	(2)	63
Finance income (2) (3)	–	–	–	58	–	–	58
Other	–	–	–	121	–	(2)	119
Regulated gas revenue	–	–	–	1,265	–	(4)	1,261
Non-Regulated							
Marketing and trading margin (4)	–	–	–	–	102	–	102
Energy sales	–	–	–	–	21	(21)	–
Other	–	–	–	14	9	–	23
Mark-to-market (3)	–	–	–	–	(289)	3	(286)
Non-regulated revenue	–	–	–	14	(157)	(18)	(161)
Total operating revenues	**$ 2,724**	**$ 1,501**	**$ 445**	**$ 1,280**	**$ (157)**	**$ (28)**	**$ 5,765**

(1) Other includes rental revenues, which do not represent revenue from contracts with customers.
(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy Canada.
(3) Revenue which does not represent revenues from contracts with customers.
(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter-segment Eliminations	Total
For the year ended December 31, 2020							
Regulated Electric Revenue							
Residential	$ 1,365	$ 806	$ 179	$ –	$ –	$ –	$ 2,350
Commercial	678	405	233	–	–	–	1,316
Industrial	178	224	32	–	–	–	434
Other electric and regulatory deferrals	242	31	8	–	–	–	281
Other (1)	17	28	22	1	–	(7)	61
Regulated electric revenue	2,480	1,494	474	1	–	(7)	4,442
Regulated Gas Revenue							
Residential	–	–	–	495	–	–	495
Commercial	–	–	–	275	–	–	275
Industrial	–	–	–	54	–	–	54
Finance income (2) (3)	–	–	–	61	–	–	61
Other	–	–	–	156	–	(7)	149
Regulated gas revenue	–	–	–	1,041	–	(7)	1,034
Non-Regulated							
Marketing and trading margin (4)	–	–	–	–	38	–	38
Energy sales	–	–	–	–	16	(16)	–
Other	–	–	–	16	21	–	37
Mark-to-market (3)	–	–	–	–	(46)	1	(45)
Non-regulated revenue	–	–	–	16	29	(15)	30
Total operating revenues	$ 2,480	$ 1,494	$ 474	$ 1,058	$ 29	$ (29)	$ 5,506

(1) Other includes rental revenues, which do not represent revenue from contracts with customers.
(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy Canada.
(3) Revenue which does not represent revenues from contracts with customers.
(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

Remaining Performance Obligations

Remaining performance obligations primarily represent gas transportation contracts, lighting contracts and long-term steam supply arrangements with fixed contract terms. As of December 31, 2021, the aggregate amount of the transaction price allocated to remaining performance obligations was $437 million (2020 – $464 million). This amount includes $142 million of future performance obligations related to a gas transportation contract between SeaCoast and PGS through 2040. This amount excludes contracts with an original expected length of one year or less and variable amounts for which Emera recognizes revenue at the amount to which it has the right to invoice for services performed. Emera expects to recognize revenue for the remaining performance obligations through 2041.

7. Regulatory Assets and Liabilities

Regulatory assets represent prudently incurred costs that have been deferred because it is probable they will be recovered through future rates or tolls collected from customers. Management believes existing regulatory assets are probable for recovery either because the Company received specific approval from the applicable regulator, or due to regulatory precedent established for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is as approved by the respective regulator.

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Regulatory assets		
Deferred income tax regulatory assets	**$ 1,045**	$ 887
Tampa Electric capital cost recovery for early retired assets	**657**	–
Pension and post-retirement medical plan	**291**	394
Regulated fuel adjustment mechanism	**145**	–
NMGC winter event gas cost recovery	**117**	–
Cost recovery clauses	**114**	49
Storm restoration regulatory asset	**35**	41
Environmental remediations	**27**	28
Stranded cost recovery	**26**	26
Deferrals related to derivative instruments	**23**	65
Demand side management ("DSM") deferral	**10**	15
Unamortized defeasance costs	**10**	13
Other	**66**	66
	$ 2,566	$ 1,584
Current	**$ 253**	$ 165
Long-term	**2,313**	1,419
Total regulatory assets	**$ 2,566**	$ 1,584
Regulatory liabilities		
Deferred income tax regulatory liabilities	**863**	933
Accumulated reserve – cost of removal	**819**	865
Deferrals related to derivative instruments	**241**	15
Storm reserve	**58**	62
Cost recovery clauses	**35**	31
Self-insurance fund (note 32)	**28**	28
Regulated fuel adjustment mechanism	**–**	21
Other	**11**	6
	$ 2,055	$ 1,961
Current	**$ 290**	$ 129
Long-term	**1,765**	1,832
Total regulatory liabilities	**$ 2,055**	$ 1,961

Deferred Income Tax Regulatory Assets and Liabilities

To the extent deferred income taxes are expected to be recovered from or returned to customers in future years, a regulatory asset or liability is recognized as appropriate.

Tampa Electric Capital Cost Recovery for Early Retired Assets

This regulatory asset is related to the remaining net book value of Big Bend Power Station Units 1 through 3 and smart meter assets that were retired. The balance earns a rate of return as permitted by the FPSC and will be recovered as a separate line item on customer bills for a period of 15 years. This recovery mechanism is authorized by and survives the term of the settlement agreement approved by the FPSC in 2021. See "Tampa Electric Big Bend Modernization Project" below for further information.

Pension and Post-Retirement Medical Plan

This asset is primarily related to the deferred costs of pension and post-retirement benefits at Tampa Electric, PGS and NMGC. It is included in rate base and earns a rate of return as permitted by the FPSC and New Mexico Public Regulation Commission ("NMPRC") as applicable. It is amortized over the remaining service life of plan participants.

Regulated Fuel Adjustment Mechanism

This regulated asset is the difference between actual fuel costs and amounts recovered from NSPI customers through electricity rates in a given year, and deferred to a fuel adjustment mechanism ("FAM") regulatory asset or liability and recovered from or returned to customers in a subsequent year. As approved on December 6, 2019 as part of NSPI's three-year fuel stability plan, differences between actual fuel costs and fuel revenues recovered from customers for the years 2020 to 2022, will be recovered or returned to customers after 2022. The Nova Scotia Utility and Review Board's ("UARB") decision to approve the fuel stability plan directed that any annual non-fuel revenues above NSPI's approved range of ROE are to be applied to the FAM.

NMGC Winter Event Gas Cost Recovery

In February 2021, the State of New Mexico experienced an extreme cold weather event that resulted in an incremental $108 million USD for gas costs above what it would normally have paid during this period. NMGC normally recovers gas supply and related costs through a purchased gas adjustment clause. On April 16, 2021, NMGC filed a Motion for Extraordinary Relief, as permitted by the NMPRC rules, to extend the terms of the repayment of the incremental gas costs and to recover a carrying charge. On June 15, 2021, the NMPRC approved the recovery of $108 million USD and related borrowing costs over a period of 30 months beginning July 1, 2021.

Cost Recovery Clauses

These assets and liabilities are related to Tampa Electric, PGS and NMGC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in a subsequent period.

Storm Restoration Regulatory Asset

This asset represents storm restoration costs, primarily incurred by GBPC. GBPC maintains insurance for its generation facilities and, as with most utilities, its transmission and distribution networks are not covered by commercial insurance.

In January 2020, the Grand Bahama Port Authority ("GBPA") approved the recovery of $15 million USD of costs related to Hurricane Dorian in 2019, over a five-year period. The recovery was implemented through rates on January 1, 2021.

Restoration costs associated with Hurricane Matthew in 2016 are being recovered through an approved fuel charge. Additional details on the recovery are included under the GBPC section below. The balance of the regulatory asset as at December 31, 2021 is $12 million USD.

Environmental Remediations

This asset is primarily related to PGS costs associated with environmental remediation at Manufactured Gas Plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is based on a settlement agreement approved by the FPSC.

Stranded Cost Recovery

Due to the decommissioning of a GBPC steam turbine in 2012, the GBPA approved the recovery of a $21 million USD stranded cost through electricity rates; it is included in rate base and is expected to be included in rates in future years.

Deferrals Related to Derivative Instruments

This asset is primarily related to NSPI deferring changes in fair value of derivatives that are documented as economic hedges or that do not qualify for NPNS exemption, as a regulatory asset or liability as approved by its regulator. The realized gain or loss is recognized when the hedged item settles in regulated fuel for generation and purchased power, inventory, operating, maintenance or general or property, plant and equipment, depending on the nature of the item being economically hedged.

DSM Deferral

The UARB approved implementation of the 2015 DSM deferral set at $35 million in 2015 and recoverable from customers over an 8-year period beginning in 2016.

The UARB directed EfficiencyOne, a franchisee appointed by the Province of Nova Scotia to provide NSPI with electricity efficiency and conservation activities under the *Public Utilities Act*, to review financing options through which EfficiencyOne would borrow the 2015 deferral amount from a commercial lender in order to repay NSPI the amount it expended on behalf of its customers in 2015. In December 2016, EfficiencyOne secured financing and $31 million was advanced to NSPI to finance the 2015 DSM deferral. In February 2017, EfficiencyOne advanced an additional $2 million to NSPI. As NSPI collects the associated amounts from customers over the remaining three years, it will repay the balance to EfficiencyOne. This has been set up as a liability in "Other long-term liabilities" with the current portion of the liability included in "Other current liabilities" on the Consolidated Balance Sheets.

Unamortized Defeasance Costs

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust that provide the principal and interest streams to match the related defeased debt, which as at December 31, 2021, totalled $200 million (2020 – $582 million). The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB.

Accumulated Reserve – Cost of Removal ("COR")

This regulatory liability represents the non-ARO COR reserve in Tampa Electric, PGS, NMGC and NSPI. AROs represent the fair value of estimated cash flows associated with the Company's legal obligation to retire its property, plant and equipment. Non-ARO COR represent estimated funds received from customers through depreciation rates to cover future COR of property, plant and equipment value upon retirement that are not legally required. This reduces rate base for ratemaking purposes. This liability is reduced as COR are incurred and increased as depreciation is recorded for existing assets and as new assets are put into service.

Storm Reserve

The storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric and PGS systems. As allowed by the FPSC, if the charges to the storm reserve exceed the storm liability, the excess is to be carried as a regulatory asset. Tampa Electric and PGS can petition the FPSC to seek recovery of restoration costs over a 12-month period, or longer, as determined by the FPSC, as well as replenish the reserve. In 2021, 2020 and 2019, Tampa Electric incurred storm restoration preparation costs for multiple hurricanes of approximately $10 million USD, which was charged to the storm reserve regulatory liability.

REGULATORY ENVIRONMENTS

Florida Electric Utility

Tampa Electric is regulated by the FPSC and is also subject to regulation by the Federal Energy Regulatory Commission ("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.

Tampa Electric's approved regulated return on equity ("ROE") range for 2021 and 2020 was 9.25 per cent to 11.25 per cent based on an allowed equity capital structure of 54 per cent. An ROE of 10.25 per cent is used for the calculation of the return on investments for clauses. Beginning in 2022, Tampa Electric's approved regulated ROE range is 9.00 per cent to 11.00 per cent, based on an allowed equity capital structure of 54 per cent. An ROE of 9.95 per cent will be used for the calculation of the return on investments for clauses. See below for further detail.

Fuel Recovery

Tampa Electric has a fuel recovery clause approved by the FPSC, allowing the opportunity to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. The FPSC annually approves cost-recovery rates for purchased power, capacity, environmental and conservation costs, including a return on capital invested. Differences between the prudently incurred fuel costs and the cost-recovery rates and amounts recovered from customers through electricity rates in a year are deferred to a regulatory asset or liability and recovered from or returned to customers in a subsequent year.

On January 19, 2022, Tampa Electric requested a mid-course adjustment to its fuel and capacity charges to recover an additional $169 million USD, effective with April 2022 customer bills, due to an increase in fuel commodity and capacity costs. The FPSC is expected to issue its decision in March 2022.

On July 19, 2021, Tampa Electric requested a mid-course adjustment of $83 million USD to its fuel and capacity charges, effective with September 2021 customer bills, due to an increase in fuel commodity and capacity costs in 2021. On August 3, 2021, the FPSC approved the request to recover the costs during the months of September through December 2021.

Base Rates

On August 6, 2021, Tampa Electric filed with the FPSC a joint motion for approval of a settlement agreement (the "Settlement Agreement") by Tampa Electric and the intervenors in relation to its rate case filed with the FPSC in April 2021. The Settlement Agreement provides for a projected increase of $191 million USD in rates annually, effective with January 2022 bills. This increase will consist of $123 million USD in base rate charges and $68 million USD to recover the costs of retiring assets including, Big Bend coal generation assets Units 1 through 3 and meter assets. The Settlement Agreement further includes two subsequent year adjustments of $90 million USD and $21 million USD, effective January 2023 and January 2024, respectively related to the recovery of future investments in the Big Bend Modernization project and solar generation. The allowed equity in the capital structure will continue to be 54 per cent from investor sources of capital. The Settlement Agreement includes an allowed regulated ROE range of 9.0 per cent to 11.0 per cent with a 9.95 per cent midpoint. It also provides for a 25 basis point increase in the allowed ROE range and mid-point, and $10 million USD of additional revenue, if U.S. Treasury Bond yields exceed a specific threshold set on the date the FPSC votes to approve the agreement. Under the agreement, base rates will not further change from January 1, 2022 through December 31, 2024, unless Tampa Electric's earned ROE were to fall below the bottom of the range during that time. The Settlement Agreement contains a provision whereby Tampa Electric agrees to quantify the future impact of a change in tax rates on net operating income through a reduction or increase in base revenues within 180 days of when such tax change becomes law or its effective date. The Settlement Agreement further creates a mechanism to recover the costs of retiring coal generation units and meter assets over a period of 15 years which survives the term of that agreement. The Settlement Agreement sets new depreciation and dismantlement rates effective January 1, 2022 and contains the provisions that Tampa Electric will not have to file another depreciation study during the term of the agreement but will file a new depreciation study no more than one year, nor less than 90 days, before the filing of its next general base rate proceeding. Tampa Electric agreed not to hedge natural gas through the period ending on December 31, 2024. On October 21, 2021, the FPSC approved the Settlement Agreement and the final order, reflecting such approval, was issued in November 2021.

On April 9, 2019, Tampa Electric reached a settlement agreement with consumer parties regarding eligible storm costs as a result of Hurricane Irma in 2017, which was approved by the FPSC on May 21, 2019. As a result, Tampa Electric refunded $12 million USD to customers in January 2020, resulting in minimal impact to the Consolidated Statements of Income.

Solar Base Rate Adjustments Included in Base Rates

As of December 31, 2021, Tampa Electric has invested $850 million USD in 600 MW of utility-scale solar photovoltaic projects, which are recoverable through FPSC-approved solar base rate adjustments ("SoBRAs"). AFUDC is being earned on these projects during construction. The FPSC has approved SoBRAs representing a total of 600 MW or $104 million USD annually in estimated revenue requirements for in-service projects.

The true-up filing for SoBRAs tranche 1 and 2 revenue requirement estimates that were included in base rates as of September 2018 and January 2019, respectively, was submitted on April 30, 2020, and the FPSC approved the amount on August 18, 2020. A $5 million USD true-up was returned to customers in 2020. On October 12, 2021, the FPSC approved the true-up filing for SoBRA tranche 3, included in base rates as of January 2020. An estimated $4 million true-up was returned to customers during 2021. The true-up for SoBRA tranche 4 will be filed in early 2022.

Storm Protection Cost Recovery Clause and Settlement Agreement

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

The June 9, 2020 settlement agreement approved by the FPSC disclosed above also included approval of Tampa Electric's petition to eliminate its $16 million USD accumulated amortization reserve surplus for intangible software assets through a credit to amortization expense in 2020.

Big Bend Modernization Project

Tampa Electric expects to invest approximately $850 million USD during 2018 through 2023 to modernize the Big Bend Power Station, of which approximately $695 million USD has been invested through December 31, 2021. The modernization project will repower Big Bend Unit 1 with natural gas combined-cycle technology and eliminate coal as this unit's fuel. As part of the modernization project, Tampa Electric retired the Unit 1 components that will not be used in the modernized plant in 2020 and Big Bend Unit 2 in 2021. Tampa Electric plans to retire Big Bend Unit 3 in 2023 as it is in the best interest of the customers from an economic, environmental risk and operational perspectives.

At December 31, 2021, the balance sheet included $636 million USD in electric utility plant and $267 million USD in accumulated depreciation related to Unit 1 components and Unit 2 and Unit 3 assets. In accordance with Tampa Electric's 2017 settlement agreement approved by the FPSC, Tampa Electric continued to account for its existing investment in Unit 1, 2 and 3 in electric utility plant and depreciate the assets using the current depreciation rates until December 31, 2021, at which point they were reclassified to a regulatory asset on the balance sheet.

Tampa Electric's Settlement Agreement provides recovery for the Big Bend Modernization project in two phases. The first phase is a revenue increase to cover the costs of the assets in service during 2022, among other items. The remainder of the project costs will be recovered as part of the 2023 subsequent year adjustment. The Settlement Agreement also includes a new charge to recover the remaining costs of the retiring Big Bend coal generation assets, Units 1 through 3, which will be spread over 15 years and will survive the termination of the Settlement Agreement. The special capital recovery schedule for all three units was applied beginning January 1, 2022.

Canadian Electric Utilities

NSPI

NSPI is a public utility as defined in the *Public Utilities Act of Nova Scotia* ("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 also subject to UARB approval.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide a reasonable return to investors. NSPI's approved regulated ROE range for 2021 and 2020 was 8.75 per cent to 9.25 per cent based on an actual five quarter average regulated common equity component of up to 40 per cent.

NSPI has a FAM, approved by UARB which enables it to seek recovery of its fuel costs from customers through regularly scheduled fuel rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent years.

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

On January 27, 2022, NSPI filed a General Rate Application ("GRA") with the UARB. The GRA proposes a rate stability plan for 2022 through 2024 which includes average base rate increases of 2.9 per cent per year and average fuel rate increases pursuant to the 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. A decision by the UARB is expected later this year.

The Maritime Link is a $1.8 billion (including AFUDC) transmission project including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. The Maritime Link entered service on January 15, 2018 and NSPI started interim assessment payments to NSPML at that time. The UARB approved 2021 interim cost assessment recovery payment to NSPML was $172 million (2020 – $145 million) and as of December 31, 2021 $139 million (2020 – $135 million) has been paid. The approved interim cost assessment payments are subject to a holdback of up to $10 million pending UARB agreement that benefits from the Maritime Link are realized for NSPI customers. For 2021, NSPI has recorded a $10 million (2020 – $4 million) holdback payable to NSPML and NSPML has deferred collection of $23 million in depreciation expense in 2021. On January 18, 2022, the UARB directed NSPI to pay to NSPML approximately $10 million of the 2021 holdback.

As part of a three-year fuel stability plan, electricity rates have been set to include the $145 million approved Maritime Link assessment for 2020 and amounts of $164 million and $162 million for 2021 and 2022, respectively. Any difference between the amounts included in the fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

In response to the delayed timing of energy delivery from the Muskrat Falls project, which is being developed by Nalcor Energy, the approved Maritime Link interim assessment payment in 2019 reflected a reduction in NSPML's assessment, related to depreciation and amortization expenses. The UARB's decision to approve NSPI's 2020 through 2022 fuel stability plan outlined the treatment of the reduced 2019 NSPML assessment of $52 million plus interest. NSPI refunded approximately $40 million plus interest to customers, and the remaining $12 million plus interest will be returned to customers subsequent to 2022.

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.

Nalcor's NS Block delivery obligations commenced on August 15, 2021 and delivery will continue over the next 35 years pursuant to the agreements. On August 9, 2021, NSPML filed a final capital cost application with the UARB seeking approval to recover capital costs associated with the Maritime Link and approval of NSPML's 2022 assessment. In December 2021, NSPML obtained an interim decision from the UARB approving interim rates beginning January 1, 2022, until receipt of the UARB's decision on the application. On February 9, 2022, the UARB issued its decision relating to the Maritime Link Project, approving NSPML's requested rate base of approximately $1.8 billion less costs that would not otherwise have been recoverable if incurred by NSPI. The UARB also approved approximately $168 million of NSPML revenue requirement in 2022 subject to a holdback of $2 million per month beginning April 1, 2022 and thereafter to the end of the year. This holdback is to be used to fund any replacement energy costs incurred by NSPI due to a 10 per cent or greater shortfall in contracted NS Block deliveries each month and will otherwise be released to NSPML. NSPML is required to provide the UARB with a compliance filing by February 16, 2022 which will confirm the impacts of this decision including the amount of the unrecoverable items which are not expected to exceed $10 million (pre-tax).

Other Electric Utilities

The Barbados Light & Power Company Limited

BLPC is regulated by the Fair Trading Commission ("FTC"), an independent regulator, under the Utilities Regulation (Procedural) Rules 2003. The Government of Barbados has granted BLPC a franchise to generate, transmit and distribute electricity on the island until 2028. In 2019, the Government of Barbados passed legislation amending the number of licenses required for the supply of electricity from a single integrated license which currently exists to multiple licenses for Generation, Transmission and Distribution, Storage, Dispatch and Sales. 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. Following a general election called late in 2021 for January 19, 2022, the new licenses are expected to take effect in 2022 on completion of the legislative process. The Dispatch license will have a term of 5 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 currently assessing the full impact of the new licenses on its business and working towards the successful implementation of the licenses.

BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide an appropriate return to investors. BLPC's approved regulated return on rate base was 10 per cent for 2021 and 2020.

BLPC has a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner. The approved calculation of the fuel charge is adjusted monthly and reported to the regulator.

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 allowed regulatory ROE of 12.50 per cent on an allowed equity capital structure of 65 per cent. A decision is expected from the FTC in the second half of 2022.

On October 21, 2021 the FTC approved BLPC's application to implement a fuel hedging program which will be incorporated into the calculation of the fuel clause adjustment. On November 10, 2021 BLPC requested the FTC review the required 50/50 cost sharing arrangement between BLPC and customers in relation to the hedging administrative costs, or any gains and losses associated with the hedging program. A decision is expected from the FTC in the first half of 2022.

In December 2018, the Government of Barbados signed the Income Tax Amendment Act into law. This legislation, which was effective January 1, 2019, created a new corporate income tax rate schedule and eliminated certain tax credits. At the date of enactment, BLPC was required to remeasure its deferred income tax liability at the new lower corporate income tax rate, resulting in recognition of an income tax recovery of $10 million USD of which $7 million USD was deferred as a regulatory liability, all of which was recognized in earnings in Q1 2020.

Grand Bahama Power Company Limited

GBPC is regulated by the GBPA. The GBPA has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit and distribute electricity on the island until 2054. There is a fuel pass-through mechanism and tariff review policy with new rates submitted every three years. GBPC's approved regulated return on rate base was 8.37 per cent for 2021 (2020 – 8.34 per cent).

On January 14, 2022, the GBPA issued its decision on GBPC's application for rate review that was filed with the GBPA on September 23, 2021. The decision, which becomes 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.

In 2017, as part of the recovery of costs incurred as a result of Hurricane Matthew, the GBPA approved a fixed per kWh fuel charge and allowed the difference between this and the actual cost of fuel to be applied to the Hurricane Matthew regulatory asset. In September 2021, GBPC filed an application for rate review with the GBPA. As part of its decision issued January 14, 2022 and effective April 1, 2022, the GBPA approved the continued amortization of the remaining regulatory asset over the three year period ending December 31, 2024.

Dominica Electricity Services Ltd.

Domlec is regulated by the Independent Regulatory Commission, Dominica. On October 7, 2013, the Independent Regulatory Commission, Dominica issued a Transmission, Distribution & Supply License and a Generation License, both of which came into effect on January 1, 2014, for a period of 25 years. Domlec's approved allowable regulated return on rate base was 15 per cent for 2021 and 2020.

Domlec has a fuel pass-through mechanism which provides opportunity to recover substantially all prudently incurred fuel costs in a timely manner.

Gas Utilities and Infrastructure

PGS

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

PGS's approved ROE range for 2021 was 8.9 per cent to 11.0 per cent with a 9.9 per cent midpoint, based on an allowed equity capital structure of 54.7 per cent. PGS's approved ROE range for 2020 was 9.25 per cent to 11.75 per cent, based on an allowed equity capital structure of 54.7 per cent. An ROE of 10.75 per cent was used for the calculation of return on investments for clauses.

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

The FPSC annually approves cost-recovery rates for conservation costs and Cast Iron/Bare Steel Pipe Replacement costs, including a return on capital invested incurred in developing and implementing energy conservation programs. The Cast Iron/ Bare Steel Pipe Replacement clause is to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. The FPSC approved a replacement program of approximately 5 per cent, or 800 kilometres, of the PGS system at a cost of approximately $80 million USD over a 10-year period beginning in 2013. In February 2017, the FPSC approved an amendment to the cast iron bare steel rider to include certain plastic materials and pipe deemed obsolete by Pipeline and Hazardous Materials Safety Administration, totaling approximately 880 kilometres. PGS estimates that the majority of cast iron and bare steel pipe will be removed from its system by the end of 2022, with the replacement of obsolete plastic pipe continuing until 2028 under the rider.

On November 19, 2020, the FPSC approved a settlement agreement filed by PGS. The settlement agreement allows for an increase to base rates by $58 million USD annually effective January 1 2021, which is a $34 million USD increase in revenue and $24 million USD increase of revenues previously recovered through the cast iron and bare steel replacement rider. It provides PGS the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS has not reversed any of this accumulated depreciation to date. In addition, the agreement sets new depreciation rates effective January 1, 2021. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2023, unless its earned ROE were to fall below 8.9 per cent before that time with an allowed equity in the capital structure of 54.7 per cent from investor sources of capital. The settlement agreement provides for the deferral of income taxes as a result of changes in tax laws. The changes would be reflected as a regulatory asset or liability and either result in an increase or a decrease in customer rates through a subsequent regulatory process.

NMGC

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.

NMGC's approved ROE for 2021 was 9.375 per cent on an allowed equity capital structure of 52 per cent. The approved ROE for 2020 was 9.10 per cent on an allowed capital structure of 52 per cent.

NMGC recovers gas supply costs through a purchased gas adjustment clause ("PGAC"). This clause recovers NMGC's actual costs for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, transmission, distribution, and sale of natural gas to its customers. On a monthly basis, NMGC can adjust the charges based on the next month's expected cost of gas and any prior month under-recovery or over-recovery. The NMPRC requires that NMGC annually file a reconciliation of the PGAC period costs and recoveries. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that the continued use of the PGAC is reasonable and necessary. In December 2020, NMGC received approval of its PGAC Continuation Filing for the four-year period ending December 2024.

In February 2021, the State of New Mexico experienced an extreme cold weather event that resulted in an incremental $108 million USD for gas costs above what it would normally have paid during this period. On June 15, 2021, the NMPRC approved the recovery over a period of 30 months beginning July 1, 2021. For more information, refer to the "NMGC Winter Event Gas Cost Recovery" section above.

On December 16, 2020, the NMPRC approved a settlement agreement for new rates that became effective on January 1, 2021. The new rates reflect the recovery of capital investment in pipelines and related infrastructure and resulted in an increase in revenue of approximately $5 million USD annually.

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 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.

Brunswick Pipeline

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Canaport™ LNG import terminal near Saint John, New Brunswick to markets in the northeastern United States. Brunswick Pipeline entered into a 25-year firm service agreement commencing in July 2009 with Repsol Energy Canada. The agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract. The pipeline is considered a Group II pipeline regulated by the Canada Energy Regulator ("CER"). The CER Gas Transportation Tariff is filed by Brunswick Pipeline in compliance with the requirements of the *CER Act* and sets forth the terms and conditions of the transportation rendered by Brunswick Pipeline.

8. Investments Subject to Significant Influence and Equity Income

millions of Canadian dollars	Carrying Value As at December 31 **2021**	2020	Equity Income For the year ended December 31 **2021**	2020	Percentage of Ownership **2021**
LIL (1)	**$ 682**	$ 629	**$ 54**	$ 49	**37.4**
NSPML	**533**	547	**49**	47	**100.0**
M&NP (2)	**123**	129	**20**	20	**12.9**
Lucelec (2)	**44**	41	**4**	4	**19.5**
Bear Swamp (3)	**–**	–	**16**	29	**50.0**
	$ 1,382	$ 1,346	**$ 143**	$ 149	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.9 per cent of the total units issued. Percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined upon final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments.

(2) Although Emera's ownership percentage of these entities is relatively low, it is considered to have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in these entities using the equity method.

(3) The investment balance in Bear Swamp is in a credit position primarily as a result of a $179 million distribution received in 2015. Bear Swamp's credit investment balance of $104 million (2020 – $118 million) is recorded in Other long-term liabilities on the Consolidated Balance Sheets.

Equity investments include a $8 million difference between the cost and the underlying fair value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 32). NSPML's consolidated summarized balance sheets are illustrated as follows:

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Balance Sheets		
Current assets	**$ 25**	$ 57
Property, plant and equipment	**1,587**	1,629
Regulatory assets	**247**	210
Non-current assets	**31**	32
Total assets	**$ 1,890**	$ 1,928
Current liabilities	**$ 50**	$ 56
Long-term debt (1)	**1,189**	1,228
Non-current liabilities	**118**	97
Equity	**533**	547
Total liabilities and equity	**$ 1,890**	$ 1,928

(1) The project debt has been guaranteed by the Government of Canada.

9. Other Income, Net

Other income, net consisted of the following:

For the millions of Canadian dollars	Year ended December 31 2021	2020
Allowance for equity funds used during construction	**$ 61**	$ 45
Gain on sale of Emera Maine, net of transaction costs (1)	**–**	585
TECO Guatemala Holdings award (2)	**–**	49
Other	**32**	29
	$ 93	$ 708

(1) Refer to note 4 for further detail related to the gain on sale of Emera Maine.
(2) Refer to note 27 for further detail related to the TECO Guatemala Holdings award.

10. Income Taxes

The income tax provision, for the years ended December 31, differs from that computed using the enacted combined Canadian federal and provincial statutory income tax rate for the following reasons:

millions of Canadian dollars	2021	2020
Income before provision for income taxes	**$ 555**	$ 1,325
Statutory income tax rate	**29.0%**	29.5%
Income taxes, at statutory income tax rate	**161**	391
Additional impact from the sale of Emera Maine	**–**	102
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(62)**	(48)
Foreign tax rate variance	**(42)**	(45)
Amortization of deferred income tax regulatory liabilities	**(33)**	(44)
Tax effect of equity earnings	**(16)**	(15)
Tax credits	**(13)**	(12)
Revaluation of deferred income taxes due to change in Nova Scotia tax rate	**–**	12
Other	**(1)**	–
Income tax (recovery) expense	**$ (6)**	$ 341
Effective income tax rate	**(1%)**	26%

The change in the effective income tax rate was primarily due to decreased income before provision for income taxes and the additional impact from the sale of Emera Maine in 2020.

On March 10, 2020, Bill 243 of the Nova Scotia Financial Measures (2020) Act was enacted, which included a reduction in the Nova Scotia provincial corporate income tax rate. As a result, the Company's combined Canadian federal and provincial statutory income tax rate was reduced from 31 per cent to 29.5 per cent for 2020, and further reduced to 29 per cent for 2021 onward.

As a result of the change in tax rate in 2020, the Company recorded a reduction of $52 million to its net deferred income tax liabilities and an offsetting reduction to its net deferred income tax regulatory asset, as the benefit of lower net deferred income tax liabilities is expected to be returned to customers in future years. The Company also recognized a $12 million income tax expense as a result of the revaluation of certain net deferred income tax assets.

On March 27, 2020, the United States Coronavirus Aid, Relief, and Economic Security (CARES) Act ("the CARES Act") was signed into law. Under the CARES Act, companies can accelerate the refund of alternative minimum tax ("AMT") credit carryforwards. As a result, the Company received the balance of its $145 million of refundable AMT credit carryforwards in 2020. The Company has not had any other material impacts from the CARES Act.

The following table reflects the composition of taxes on income from continuing operations presented in the Consolidated Statements of Income for the years ended December 31:

millions of Canadian dollars	2021	2020
Current income taxes		
Canada	$ 20	$ 18
United States	11	(58)
Deferred income taxes		
Canada	(33)	20
United States	118	426
Other	2	(9)
Investment tax credits		
United States	(11)	(10)
Operating loss carryforwards		
Canada	(64)	(46)
United States	(49)	–
Income tax (recovery) expense	$ (6)	$ 341

The following table reflects the composition of income before provision for income taxes presented in the Consolidated Statements of Income for the years ended December 31:

millions of Canadian dollars	2021	2020
Canada	$ 244	$ 176
United States	289	1,142
Other	22	7
Income before provision for income taxes	$ 555	$ 1,325

The deferred income tax assets and liabilities presented in the Consolidated Balance Sheets as at December 31 consisted of the following:

millions of Canadian dollars	2021	2020
Deferred income tax assets:		
Tax loss carryforwards	$ 873	$ 724
Tax credit carryforwards	375	319
Derivative instruments	188	108
Regulatory liabilities – cost of removal	170	184
Other	434	375
Total deferred income tax assets before valuation allowance	2,040	1,710
Valuation allowance	(256)	(202)
Total deferred income tax assets after valuation allowance	$ 1,784	$ 1,508
Deferred income tax (liabilities):		
Property, plant and equipment	$ (2,622)	$ (2,450)
Derivative instruments	(197)	(93)
Other	(538)	(385)
Total deferred income tax liabilities	$ (3,357)	$ (2,928)
Consolidated Balance Sheets presentation:		
Long-term deferred income tax assets	$ 295	$ 209
Long-term deferred income tax liabilities	(1,868)	(1,629)
Net deferred income tax liabilities	$ (1,573)	$ (1,420)

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that Emera is more likely than not to realize all recorded deferred income tax assets, except for certain loss carryforwards and unrealized capital losses on investments. A valuation allowance of $256 million has been recorded as at December 31, 2021 (2020 – $202 million) related to the loss carryforwards and investments.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, $2.9 billion as at December 31, 2021 (2020 – $2.7 billion) in cumulative temporary differences for which deferred taxes might otherwise be required, have not been recognized. It is impractical to estimate the amount of income and withholding tax that might be payable if a reversal of temporary differences occurred.

Emera's net operating loss ("NOL"), capital loss and tax credit carryforwards and their expiration periods as at December 31, 2021 consisted of the following:

millions of Canadian dollars	Tax Carryforwards	Subject to Valuation Allowance	Net Tax Carryforwards	Expiration Period
Canada				
NOL	$ 1,776	$ (791)	$ 985	2026–2041
Capital loss	75	(75)	–	Indefinite
United States				
Federal NOL	$ 1,521	$ –	$ 1,521	2032–Indefinite
State NOL	817	–	817	2032–Indefinite
Tax credit	375	–	375	2025–2041
Other				
NOL	$ 52	$ (38)	$ 14	2022–2028

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of Canadian dollars	**2021**	2020
Balance, January 1	**$ 30**	$ 29
Increases due to tax positions related to current year	**4**	1
Increases due to tax positions related to a prior year	**1**	2
Decreases due to tax positions related to a prior year	**(1)**	(2)
Decreases due to settlement with tax authorities	**(6)**	–
Balance, December 31	**$ 28**	$ 30

The total amount of unrecognized tax benefits as at December 31, 2021 was $28 million (2020 – $30 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $6 million (2020 – $6 million) with nil interest expense recognized in the Consolidated Statements of Income (2020 – $1 million). No penalties have been accrued. The balance of unrecognized tax benefits could change in the next 12 months as a result of resolving Canada Revenue Agency ("CRA") and Internal Revenue Service audits. A reasonable estimate of any change cannot be made at this time.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for NSPI's 2006 through 2010 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is $62 million, including interest. NSPI has prepaid $23 million of the amount in dispute, as required by CRA.

On November 29, 2019, NSPI filed a Notice of Appeal with the Tax Court of Canada with respect to its dispute. Should NSPI be successful in defending its position, all payments including applicable interest will be refunded. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the excess, if any, owing to CRA. The related tax deductions will be available in subsequent years.

Should NSPI be similarly reassessed by the CRA for years not currently in dispute, further payments will be required; however, the ultimate permissibility of these deductions would be similarly not in dispute.

NSPI and its advisors believe that NSPI has reported its tax position appropriately. NSPI continues to assess its options to resolving the dispute; however, the outcome of the Appeal process is not determinable at this time.

Emera files a Canadian federal income tax return, which includes its Nova Scotia and New Brunswick provincial income tax. Emera's subsidiaries file Canadian, US, Barbados, St. Lucia and Dominica income tax returns. As at December 31, 2021, the Company's tax years still open to examination by taxing authorities include 2005 and subsequent years.

11. Common Stock

Authorized: Unlimited number of non-par value common shares.

Issued and outstanding:	**2021** millions of shares	**2021** millions of Canadian dollars	2020 millions of shares	2020 millions of Canadian dollars
Balance, December 31, 2020	**251.43**	**$ 6,705**	242.48	$ 6,216
Issuance of common stock (1) (2)	**4.99**	**284**	4.54	251
Issued under Purchase Plans at market rate	**4.32**	**239**	3.99	219
Discount on shares purchased under Dividend Reinvestment Plan	**–**	**(4)**	–	(4)
Options exercised under senior management share option plan	**0.33**	**14**	0.42	20
Employee Share Purchase Plan	**–**	**4**	–	3
Balance, December 31, 2021	**261.07**	**$ 7,242**	251.43	$ 6,705

(1) As at December 31, 2020, a total of 4,544,025 common shares were issued under Emera's at-the-market program "(ATM program)" at an average price of $56.04 per share for gross proceeds of $255 million ($251 million net of issuance costs).
(2) For the year ended December 31, 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).

On August 12, 2021, Emera renewed its ATM Program that allows the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was renewed pursuant to a prospectus supplement to the Company's short form base shelf prospectus dated August 5, 2021. The ATM program is expected to remain in effect until September 5, 2023. As at December 31, 2021, an aggregate gross sales limit of $457 million remains available for issuance under the ATM program.

As at December 31, 2021, the following common shares were reserved for issuance: 6.2 million (2020 – 3.5 million) under the senior management stock option plan, 3.1 million (2020 – 3.5 million) under the employee common share purchase plan and 14.2 million (2020 – 5.1 million) under the dividend reinvestment plan ("DRIP").

The issuance of common shares under the common share compensation arrangements does not allow the plans to exceed 10 per cent of Emera's outstanding common shares. As at December 31, 2021, Emera is in compliance with this requirement.

12. Earnings Per Share

Basic earnings per share ("EPS") is determined by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period. Diluted EPS is computed by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include Company contributions to the senior management stock option plan, convertible debentures and shares issued under the dividend reinvestment plan.

The following table reconciles the computation of basic and diluted earnings per share:

For the millions of Canadian dollars (except per share amounts)	Year ended December 31 **2021**	 2020
Numerator		
Net income attributable to common shareholders	**$ 510.5**	$ 937.6
Diluted numerator	**510.5**	937.6
Denominator		
Weighted average shares of common stock outstanding	**255.9**	246.5
Weighted average deferred share units outstanding	**1.3**	1.3
Weighted average shares of common stock outstanding – basic	**257.2**	247.8
Stock-based compensation	**0.4**	0.4
Weighted average shares of common stock outstanding – diluted	**257.6**	248.2
Earnings per common share		
Basic	**$ 1.98**	$ 3.78
Diluted	**$ 1.98**	$ 3.78

13. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive income are as follows:

millions of Canadian dollars	Unrealized (loss) gain on translation of self-sustaining foreign operations	Net change in net investment hedges	(Losses) gains on derivatives recognized as cash flow hedges	Net change on available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the year ended December 31, 2021						
Balance, January 1, 2021	**$ 52**	**$ 30**	**$ 1**	**$ (1)**	**$ (161)**	**$ (79)**
Other comprehensive income (loss) before reclassifications	**(42)**	**5**	**18**	**-**	**-**	**(19)**
Amounts reclassified from accumulated other comprehensive income (loss)	**-**	**-**	**(1)**	**-**	**124**	**123**
Net current period other comprehensive income (loss)	**(42)**	**5**	**17**	**-**	**124**	**104**
Balance, December 31, 2021	**$ 10**	**$ 35**	**$ 18**	**$ (1)**	**$ (37)**	**$ 25**
For the year ended December 31, 2020						
Balance, January 1, 2020	$ 253	$ 4	$ (1)	$ (1)	$ (160)	$ 95
Other comprehensive income (loss) before reclassifications	(201)	26	-	-	-	(175)
Amounts reclassified from accumulated other comprehensive income (loss)	-	-	2	-	(1)	1
Net current period other comprehensive income (loss)	(201)	26	2	-	(1)	(174)
Balance, December 31, 2020	$ 52	$ 30	$ 1	$ (1)	$ (161)	$ (79)

The reclassifications out of accumulated other comprehensive income (loss) are as follows:

For the		Year ended December 31	
millions of Canadian dollars		**2021**	2020
	Affected line item in the Consolidated Financial Statements		
(Gains) Losses on derivatives recognized as cash flow hedges			
Foreign exchange forwards	Operating revenue - regulated	**$ -**	$ 2
Interest rate hedge	Interest expense, net	**(1)**	-
Total		**$ (1)**	$ 2
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses (gains)	Other income, net	**$ 24**	$ 15
Past service costs (gains)	Other income, net	**-**	(1)
Amounts reclassified into obligations	Pension and post-retirement benefits	**102**	(16)
Total before tax		**126**	(2)
	Income tax (expense) recovery	**(2)**	1
Total net of tax		**$ 124**	$ (1)
Total reclassifications out of AOCI, net of tax, for the period		**$ 123**	$ 1

14. Inventory

As at millions of Canadian dollars		December 31 2021		December 31 2020
Fuel	**$**	**255**	$	199
Materials		**283**		254
	$	**538**	$	453

15. Derivative Instruments

Derivative assets and liabilities relating to the foregoing categories consisted of the following:

	Derivative Assets				Derivative Liabilities			
As at millions of Canadian dollars		**December 31 2021**		December 31 2020		**December 31 2021**		December 31 2020
Cash flow hedges								
Interest rate hedge	**$**	**–**	$	1	**$**	**–**	$	–
Regulatory deferral								
Commodity swaps and forwards								
Coal purchases		**22**		1		**1**		6
Power purchases		**83**		10		**8**		34
Natural gas purchases and sales		**20**		4		**7**		2
Heavy fuel oil purchases		**21**		1		**–**		5
Foreign exchange forwards		**7**		–		**8**		17
Physical natural gas purchases and sales		**88**		–		**–**		–
		241		16		**24**		64
HFT derivatives								
Power swaps and physical contracts		**33**		13		**32**		13
Natural gas swaps, futures, forwards, physical contracts		**208**		139		**818**		346
		241		152		**850**		359
Other derivatives								
Equity derivatives		**11**		–		**–**		1
Foreign exchange forwards		**–**		15		**–**		–
		11		15		**–**		1
Total gross current derivatives		**493**		184		**874**		424
Impact of master netting agreements with intent to settle net or simultaneously		**(192)**		(86)		**(192)**		(86)
Total derivatives	**$**	**301**	$	98	**$**	**682**	$	338
Current	**$**	**195**	$	73	**$**	**533**	$	251
Long-term		**106**		25		**149**		87
Total derivatives	**$**	**301**	$	98	**$**	**682**	$	338

Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Details of master netting agreements, shown net on the Consolidated Balance Sheets, are summarized in the following table:

	Derivative Assets				Derivative Liabilities			
As at millions of Canadian dollars		**December 31 2021**		December 31 2020		**December 31 2021**		December 31 2020
Regulatory deferral	**$**	**4**	$	2	**$**	**4**	$	2
HFT derivatives		**188**		84		**188**		84
Total impact of master netting agreements with intent to settle net or simultaneously	**$**	**192**	$	86	**$**	**192**	$	86

CASH FLOW HEDGES

On May 26, 2021 the treasury lock was settled for a gain of $18 million USD that will be amortized through interest expense over 10 years. As of December 31, 2021, there were no outstanding cash flow hedges.

The amounts related to cash flow hedges recorded in income and AOCI consisted of the following:

For the millions of Canadian dollars	Year ended December 31 **2021**	2020
	Interest rate hedge	Foreign exchange forwards
Realized loss in operating revenue – regulated	**$ –**	$ (2)
Realized gain in interest expense, net	**1**	–
Total gains (losses) in net income	**$ 1**	$ (2)

As at millions of Canadian dollars	December 31 **2021**	2020
	Interest rate hedge	Interest rate hedge
Total unrealized gain in AOCI – effective portion, net of tax	**$ 18**	$ 1

The Company expects $2 million of unrealized gains currently in AOCI to be reclassified into net income within the next 12 months.

REGULATORY DEFERRAL

The Company has recorded the following changes in realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

For the millions of Canadian dollars		Year ended December 31 **2021**	
	Natural gas	**Commodity swaps and forwards**	**Foreign exchange forwards**
Unrealized gain (loss) in regulatory assets	**$ –**	**$ (7)**	**$ 9**
Unrealized gain (loss) in regulatory liabilities	**88**	**218**	**(3)**
Realized (gain) in regulatory liabilities	**–**	**(3)**	**–**
Realized (gain) loss in inventory (1)	**–**	**(8)**	**5**
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**–**	**(39)**	**5**
Total change derivative instruments	**$ 88**	**$ 161**	**$ 16**

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

For the millions of Canadian dollars			Year ended December 31 2020
	Natural gas	Commodity swaps and forwards	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	$ –	$ (36)	$ (11)
Unrealized gain (loss) in regulatory liabilities	–	3	3
Realized gain (loss) in regulatory assets	–	2	–
Realized (gain) loss in regulatory liabilities	–	14	–
Realized (gain) loss in inventory (1)	–	8	(2)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	–	24	(3)
Total change derivative instruments	$ –	$ 15	$ (13)

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

COMMODITY SWAPS AND FORWARDS

As at December 31, 2021, the Company had the following notional volumes of commodity swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

millions	2022 Purchases	2023–2024 Purchases
Natural Gas (Mmbtu)	17	22
Power (MWh)	1	2

FOREIGN EXCHANGE SWAPS AND FORWARDS

As at December 31, 2021, the Company had the following notional volumes of foreign exchange swaps and forward contracts designated for regulated deferral that are expected to settle as outlined below:

	2022	2023–2024
Foreign exchange contracts (millions of US dollars)	$ 170	$ 150
Weighted average rate	1.3047	1.2413
% of USD requirements	65%	29%

The Company reassesses foreign exchange forecasted periodically and will enter into additional hedges or unwind existing hedges, as required.

HELD-FOR-TRADING DERIVATIVES

In the ordinary course of its business, Emera enters into physical contracts for the purchase and sale of natural gas, as well as power and natural gas swaps, forwards and futures, to economically hedge those physical contracts. These derivatives are all considered HFT.

The Company has recognized the following realized and unrealized gains (losses) with respect to HFT derivatives:

For the millions of Canadian dollars	Year ended December 31 **2021**	2020
Power swaps and physical contracts in non-regulated operating revenues	**$ 4**	$ (1)
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**(142)**	205
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**–**	(4)
	$ (138)	$ 200

As at December 31, 2021, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2022	2023	2024	2025	2026
Natural gas purchases (Mmbtu)	308	91	56	26	26
Natural gas sales (Mmbtu)	335	103	30	2	2
Power purchases (MWh)	1	–	–	–	–
Power sales (MWh)	2	–	–	–	–

OTHER DERIVATIVES

As at December 31, 2021, the Company had equity derivatives in place to manage the cash flow risk associated with forecasted future cash settlements of deferred compensation obligations and foreign exchange forwards in place to manage cash flow risk associated with forecasted USD cash inflows. The equity derivative hedges the return on 2.8 million shares and extends until December of 2022. The foreign exchange forwards have a combined notional amount of $52 million USD and expire throughout 2022 and 2023.

For the millions of Canadian dollars	**2021**		Year ended December 31 2020	
	Foreign Exchange Forwards	**Equity Derivatives**	Foreign Exchange Forwards	Equity Derivatives
Unrealized gain (loss) in operating, maintenance and general	**$ –**	**$ 11**	$ –	$ (1)
Unrealized gain (loss) in other income (expense), net	**(15)**	**–**	15	–
Realized gain (loss) in operating, maintenance and general	**–**	**15**	–	(3)
Realized gain (loss) in other income (expense)	**18**	**–**	(2)	–
Total gains (losses) in net income	**$ 3**	**$ 26**	$ 13	$ (4)

CREDIT RISK

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits and derivative assets. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties, and deposits or collateral are requested on any high risk accounts.

The Company assesses the potential for credit losses on a regular basis and, where appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

As at December 31, 2021, the maximum exposure the Company has to credit risk is $1.3 billion (2020 – $805 million), which includes accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The total cash deposits/collateral on hand as at December 31, 2021 was $341 million (2020 – $251 million), which mitigates the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements ("ISDA"), North American Energy Standards Board agreements ("NAESB") and, or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2021, the Company had $114 million (2020 – $123 million) in financial assets, considered to be past due, which have been outstanding for an average 57 days. The fair value of these financial assets is $93 million (2020 – $101 million), the difference of which is included in the allowance for credit losses. These assets primarily relate to accounts receivable from electric and gas revenue.

CONCENTRATION RISK

The Company's concentrations of risk consisted of the following:

As at	**December 31, 2021**		December 31, 2020	
	millions of Canadian dollars	**% of total exposure**	millions of Canadian dollars	% of total exposure
Receivables, net				
Regulated utilities				
Residential	**$ 384**	**24%**	$ 341	32%
Commercial	**167**	**10%**	143	14%
Industrial	**54**	**3%**	49	5%
Other	**91**	**6%**	96	9%
	696	**43%**	629	60%
Trading group				
Credit rating of A- or above	**66**	**4%**	54	5%
Credit rating of BBB- to BBB+	**107**	**7%**	41	4%
Not rated	**132**	**8%**	75	7%
	305	**19%**	170	16%
Other accounts receivable	**329**	**20%**	159	15%
	1,330	**82%**	958	91%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**155**	**9%**	60	6%
Credit rating of BBB- to BBB+	**22**	**1%**	13	1%
Not rated	**124**	**8%**	25	2%
	301	**18%**	98	9%
	$ 1,631	**100%**	$ 1,056	100%

CASH COLLATERAL

The Company's cash collateral positions consisted of the following:

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Cash collateral provided to others	**$ 212**	$ 69
Cash collateral received from others	**$ 100**	$ 6

Collateral is posted in the normal course of business based on the Company's creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt falling below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2021, the total fair value of derivatives in a liability position was $682 million (December 31, 2020 – $338 million). If the credit ratings of the Company were reduced below investment grade, the full value of the net liability position could be required to be posted as collateral for these derivatives.

16. Fair Value Measurements

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (see note 1) and uses a market approach to do so. The three levels of the fair value hierarchy are defined as follows:

Level 1 – Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 – Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 – Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. The primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

The following tables set out the classification of the methodology used by the Company to fair value its derivatives:

As at				December 31, 2021
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	$ –	$ 22	$ –	$ 22
Power purchases	83	–	–	83
Natural gas purchases and sales	15	1	–	16
Heavy fuel oil purchases	3	18	–	21
Foreign exchange forwards	–	7	–	7
Physical natural gas purchases and sales	–	–	88	88
	101	48	88	237
HFT derivatives				
Power swaps and physical contracts	4	5	4	13
Natural gas swaps, futures, forwards, physical contracts and related transportation	(1)	29	12	40
	3	34	16	53
Other derivatives				
Equity derivatives	11	–	–	11
Total assets	115	82	104	301
Liabilities				
Regulatory deferral				
Commodity swaps and forwards				
Power purchases	7	–	–	7
Natural gas purchases and sales	–	5	–	5
Foreign exchange forwards	–	8	–	8
	7	13	–	20
HFT derivatives				
Power swaps and physical contracts	4	5	3	12
Natural gas swaps, futures, forwards and physical contracts	13	122	515	650
	17	127	518	662
Total liabilities	24	140	518	682
Net assets (liabilities)	$ 91	$ (58)	$ (414)	$ (381)

As at				December 31, 2020
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Interest rate hedge	$ 1	$ –	$ –	$ 1
	1	–	–	1
Regulatory deferral				
Commodity swaps and forwards				
Power purchases	9	–	–	9
Natural gas purchases and sales	2	1	–	3
Heavy fuel oil purchases	–	2	–	2
	11	3	–	14
HFT derivatives				
Power swaps and physical contracts	3	2	2	7
Natural gas swaps, futures, forwards, physical contracts and related transportation	1	48	12	61
	4	50	14	68
Other derivatives				
Foreign exchange forwards	–	15	–	15
	–	15	–	15
Total assets	16	68	14	98
Liabilities				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	–	4	–	4
Power purchases	33	–	–	33
Heavy fuel oil purchases	3	3	–	6
Natural gas purchases and sales	–	2	–	2
Foreign exchange forwards	–	17	–	17
	36	26	–	62
HFT derivatives				
Power swaps and physical contracts	4	2	1	7
Natural gas swaps, futures, forwards and physical contracts	1	10	257	268
	5	12	258	275
Other derivatives				
Equity derivatives	1	–	–	1
	1	–	–	1
Total liabilities	42	38	258	338
Net assets (liabilities)	$ (26)	$ 30	$ (244)	$ (240)

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2021 was as follows:

	Regulatory Deferral	HFT Derivatives		
millions of Canadian dollars	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1, 2021	$ –	$ 2	$ 12	$ 14
Unrealized gains included in regulatory assets or liabilities	88	–	–	88
Total realized and unrealized gains included in non-regulated operating revenues	–	2	–	2
Balance, December 31, 2021	$ 88	$ 4	$ 12	$ 104

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2021 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, January 1, 2021	$ 1	$ 257	$ 258
Total realized and unrealized losses included in non-regulated operating revenues	2	258	260
Balance, December 31, 2021	$ 3	$ 515	$ 518

Significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives include third-party sourced pricing for instruments based on illiquid markets; internally developed correlation factors and basis differentials; own credit risk; and discount rates. Internally developed correlations and basis differentials are reviewed on a quarterly basis based on statistical analysis of the spot markets in the various illiquid term markets. Discount rates may include a risk premium for those long-term forward contracts with illiquid future price points to incorporate the inherent uncertainty of these points. Any risk premiums for long-term contracts are evaluated by observing similar industry practices and in discussion with industry peers. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement.

The following table outlines quantitative information about the significant unobservable inputs used in the fair value measurements categorized within Level 3 of the fair value hierarchy:

As at					**December 31, 2021**
millions of Canadian dollars	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted Average** (1)
Assets					
Regulatory deferral – Physical natural gas purchases and sales	$ 88	Modelled pricing	Third-party pricing	$4.51 – $26.09	$9.74
			Probability of default	2.52% – 4.40%	3.31%
			Discount rate	0.01% – 1.60%	0.48%
HFT derivatives – Power swaps and physical contracts	4	Modelled pricing	Third-party pricing	$37.05 – $213.00	$93.60
			Probability of default	0.01% – 2.52%	0.45%
			Discount rate	0.00% – 1.86%	0.19%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	20	Modelled pricing	Third-party pricing	$2.18 – $20.42	$3.75
			Probability of default	0.01% – 7.38%	0.13%
			Discount rate	0.00% – 11.98%	0.37%
	(8)	Modelled pricing	Third-party pricing	$2.83 – $20.86	$10.85
			Basis adjustment	$0.00 – $0.44	$0.42
			Probability of default	0.01% – 4.17%	0.46%
			Discount rate	0.00% – 1.73%	0.21%
Total assets	**$ 104**				
Liabilities					
HFT derivatives – Power swaps and physical contracts	$ 1	Modelled pricing	Third-party pricing	$37.80 – $145.80	$111.15
			Own credit risk	0.01% – 1.48%	0.12%
			Discount rate	0.01% – 1.86%	0.31%
	2	Modelled pricing	Third-party pricing	$37.46 – $126.75	$95.02
			Correlation factor	100% – 100%	100%
			Own credit risk	0.01% – 11.16%	0.07%
			Discount rate	0.01% – 1.86%	0.21%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	458	Modelled pricing	Third-party pricing	$1.90 – $20.42	$9.12
			Own credit risk	0.01% – 7.38%	0.08%
			Discount rate	0.00% – 14.59%	1.54%
	57	Modelled pricing	Third-party pricing	$2.83 – $21.53	$12.03
			Basis adjustment	$0.00 – $1.11	$0.28
			Own credit risk	0.01% – 0.49%	0.02%
			Discount rate	0.00% – 1.73%	0.13%
Total liabilities	**$ 518**				
Net liabilities	**$ (414)**				

(1) Unobservable inputs were weighted by the relative fair value of the instruments.

As at					December 31, 2020
millions of Canadian dollars	Fair Value	Valuation Technique	Unobservable Input	Range	Weighted Average [1]
Assets					
HFT derivatives – Power swaps and physical contracts	$ 1	Modelled pricing	Third-party pricing	$20.50 – $62.45	$31.14
			Probability of default	0.02% – 9.74%	2.52%
			Discount rate	0.01% – 0.73%	0.25%
	1	Modelled pricing	Third-party pricing	$25.70 – $36.05	$29.53
			Probability of default	0.36% – 0.85%	0.60%
			Discount rate	0.06% – 0.41%	0.28%
			Correlation factor	100% – 100%	100%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	18	Modelled pricing	Third-party pricing	$1.66 – $6.22	$2.52
			Probability of default	0.02% – 2.52%	0.40%
			Discount rate	0.00% – 10.36%	0.75%
	(6)	Modelled pricing	Third-party pricing	$1.82 – $8.44	$4.66
			Basis adjustment	$0.00 – $1.33	$0.44
			Probability of default	0.02% – 12.58%	1.95%
			Discount rate	0.00% – 0.67%	0.13%
Total assets	$ 14				
Liabilities					
HFT derivatives – Power swaps and physical contracts	$ 1	Modelled pricing	Third-party pricing	$1.13 – $62.45	$36.90
			Own credit risk	0.02% – 6.85%	2.02%
			Discount rate	0.01% – 0.73%	0.34%
	1	Modelled pricing	Third-party pricing	$37.25 – $62.45	$55.00
			Own credit risk	0.36% – 1.28%	0.83%
			Discount rate	0.01% – 0.40%	0.31%
			Correlation factor	100% – 100%	100%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	226	Modelled pricing	Third-party pricing	$1.44 – $6.57	$3.68
			Own credit risk	0.02% – 2.52%	0.10%
			Discount rate	0.00% – 8.79%	0.43%
	30	Modelled pricing	Third-party pricing	$1.54 – $8.44	$4.69
			Basis adjustment	$0.00 – $1.33	$0.87
			Own credit risk	0.03% – 12.58%	0.10%
			Discount rate	0.00% – 0.67%	0.16%
Total liabilities	$ 258				
Net assets (liabilities)	$ (244)				

(1) Unobservable inputs were weighted by the relative fair value of the instruments.

Long-term debt is a financial liability not measured at fair value on the Consolidated Balance Sheets. The balance consisted of the following:

As at millions of Canadian dollars	Carrying Amount	Fair Value	Level 1	Level 2	Level 3	Total
December 31, 2021	**$ 14,658**	**$ 16,775**	**$ –**	**$ 16,308**	**$ 467**	**$ 16,775**
December 31, 2020	$ 13,721	$ 16,487	$ –	$ 16,020	$ 467	$ 16,487

The Company has designated $1.2 billion USD denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations. The Company's Hybrid Notes are contingently convertible into preferred shares in the event of bankruptcy or other related events. A redemption option on or after June 15, 2026 is available and at the control of the Company. The Hybrid Notes are classified as Level 2 financial assets. As at December 31, 2021, the fair value of the Hybrid Notes was $1.7 billion (2020 – $1.8 billion). An after-tax foreign currency gain of $5 million was recorded in OCI for the year ended December 31, 2021 (2020 – $26 million).

17. Related Party Transactions

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 $149 million for the year ended December 31, 2021 (2020 – $139 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.
- 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 $19 million for the year ended December 31, 2021 (2020 – $18 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, 2021 and at December 31, 2020.

18. Receivables and Other Current Assets

Receivables and other current assets consisted of the following:

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Customer accounts receivable – billed	**$ 767**	$ 570
Customer accounts receivable – unbilled	**318**	286
Allowance for credit losses	**(21)**	(22)
Capitalized transportation capacity (1)	**316**	200
Income tax receivable	**8**	11
Prepaid expenses	**65**	50
Other	**280**	138
	$ 1,733	$ 1,233

(1) Capitalized transportation capacity represents the value of transportation/storage received by EES on asset management agreements at the inception of the contracts. The asset is amortized over the term of each contract.

19. Leases

LESSEE

The Company has operating leases for buildings, land, telecommunication services, and rail cars. Emera's leases have remaining lease terms of 1 year to 64 years, some of which include options to extend the leases for up to 64 years. These options are included as part of the lease term when it is considered reasonably certain that they will be exercised.

As at millions of Canadian dollars	Classification	**December 31 2021**	December 31 2020
Right-of-use asset	Other long-term assets	**$ 58**	$ 61
Lease liabilities			
Current	Other current liabilities	**3**	3
Long-term	Other long-term liabilities	**59**	60
Total lease liabilities		**$ 62**	$ 63

The Company has recorded lease expense of $150 million for the year ended December 31, 2021 (2020 – $160 million), of which $142 million (2020 – $149 million) relates to variable costs for power generation facility finance leases, recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

Future minimum lease payments under non-cancellable operating leases for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2022	2023	2024	2025	2026	Thereafter	Total
Minimum lease payments	$ 5	$ 6	$ 5	$ 4	$ 3	$ 112	$ 135
Less imputed interest							(73)
Total							$ 62

Additional information related to Emera's leases is as follows:

For the	**Year ended December 31 2021**	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of Canadian dollars)	**$ 7**	$ 7
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases (millions of Canadian dollars)	**$ –**	$ 7
Weighted average remaining lease term (years)	**44**	43
Weighted average discount rate – operating leases	**3.98%**	3.96%

LESSOR

The Company's net investment in direct finance and sales-type leases primarily relates to Brunswick Pipeline, compressed natural gas ("CNG") stations and heat pumps.

Direct finance and sales-type lease unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease and is recorded as "Operating revenues – regulated gas" and "Other income, net" on the Consolidated Statements of Income.

The Company manages its risk associated with the residual value of the Brunswick Pipeline lease through proper routine maintenance of the asset.

Customers have the option to purchase CNG station assets at any time after 2021 by paying a make-whole payment at the date of the purchase based on a targeted internal rate of return or may take possession of the CNG station asset at the end of the lease term for no cost. Customers have the option to purchase heat pumps at the end of the lease term for a nominal fee.

Net investment in direct finance and sales-type leases consist of the following:

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Total minimum lease payment to be received	**$ 947**	$ 1,018
Less: amounts representing estimated executory costs	**(165)**	(179)
Minimum lease payments receivable	**$ 782**	$ 839
Estimated residual value of leased property (unguaranteed)	**183**	183
Less: unearned finance lease income	**(443)**	(487)
Net investment in direct finance and sales-type leases	**$ 522**	$ 535
Principal due within one year (included in "Receivables and other current assets")	**19**	18
Net investment in sales-type leases – long-term (included in "Other long-term assets")	**41**	42
Net Investment in direct finance leases – long-term	**$ 462**	$ 475

As at December 31, 2021, future minimum lease payments to be received for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2022	2023	2024	2025	2026	Thereafter	Total
Minimum lease payments to be received	$ 78	$ 77	$ 79	$ 80	$ 78	$ 555	$ 947
Less: executory costs							(165)
Total							$ 782

20. Property, Plant and Equipment

Property, plant and equipment consisted of the following regulated and non-regulated assets:

As at millions of Canadian dollars	Estimated useful life	**December 31 2021**	December 31 2020
Generation	3 to 131	**$ 11,173**	$ 11,474
Transmission	11 to 80	**2,532**	2,414
Distribution	4 to 80	**6,305**	5,997
Gas transmission and distribution	7 to 85	**4,385**	3,879
General plant and other (1)	2 to 60	**2,473**	2,127
Total cost		**26,868**	25,891
Less: Accumulated depreciation (1)		**(8,739)**	(8,714)
		18,129	17,177
Construction work in progress (1)		**2,224**	2,358
Net book value		**$ 20,353**	$ 19,535

(1) SeaCoast owns a 50% undivided ownership interest in a jointly owned 26-mile pipeline lateral located in Florida, which went into service in 2020. At December 31, 2021, SeaCoast's share of plant in service was $27 million (2020 – $34 million), and accumulated depreciation of $1 million (2020 – nil). SeaCoast's undivided ownership interest is financed with its funds and all operations are accounted for as if such participating interest were a wholly owned facility. SeaCoast's share of direct expenses of the jointly owned pipeline is included in OM&G in the Consolidated Statements of Income.

21. Employee Benefit Plans

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees. In addition, the Company provides non-pension benefits for its retirees. These plans cover employees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Florida, New Mexico, Barbados, Dominica and Grand Bahama Island. On March 24, 2020, Emera sold Emera Maine, refer to note 4 for further detail.

Emera's net periodic benefit cost included the following:

BENEFIT OBLIGATION AND PLAN ASSETS

The changes in benefit obligation and plan assets, and the funded status for all plans were as follows:

For the millions of Canadian dollars			Year ended December 31	
	2021		2020	
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Balance, January 1	**$ 2,759**	**$ 339**	$ 2,822	$ 353
Service cost	**43**	**5**	46	5
Plan participant contributions	**6**	**4**	7	5
Interest cost	**67**	**8**	84	10
Benefits paid	**(160)**	**(27)**	(135)	(27)
Actuarial gains (losses)	**(89)**	**(10)**	189	52
Settlements and curtailments	**–**	**–**	(229)	(52)
Foreign currency translation adjustment	**(2)**	**(1)**	(25)	(7)
Balance, December 31	**2,624**	**318**	2,759	339
Change in plan assets				
Balance, January 1	**2,605**	**52**	2,593	56
Employer contributions	**42**	**21**	41	21
Plan participant contributions	**6**	**4**	7	5
Benefits paid	**(160)**	**(27)**	(135)	(27)
Actual return on assets, net of expenses	**214**	**2**	310	5
Settlements and curtailments	**–**	**–**	(191)	(7)
Foreign currency translation adjustment	**(5)**	**(1)**	(20)	(1)
Balance, December 31	**2,702**	**51**	2,605	52
Funded status, end of year	**$ 78**	**$ (267)**	$ (154)	$ (287)

The actuarial gains recognized in the period are primarily due to gains associated with changes in the discount rate and demographic assumption changes. This was partially offset by losses associated with changes in inflation and compensation-related assumptions.

PLANS WITH PBO/APBO IN EXCESS OF PLAN ASSETS

The aggregate financial position for all pension plans where the PBO or APBO (for post-retirement benefit plans) exceeds the plan assets for the years ended December 31 is as follows:

millions of Canadian dollars	**2021**		2020	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 140**	**$ 290**	$ 2,736	$ 308
Fair value of plan assets	**35**	**–**	2,568	–
Funded status	**$ (105)**	**$ (290)**	$ (168)	$ (308)

PLANS WITH ACCUMULATED BENEFIT OBLIGATION ("ABO") IN EXCESS OF PLAN ASSETS

The ABO for the defined benefit pension plans was $2,507 million as at December 31, 2021 (2020 – $2,639 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 is as follows:

millions of Canadian dollars	**2021**	2020
	Defined benefit pension plans	Defined benefit pension plans
ABO	**$ 133**	$ 1,519
Fair value of plan assets	**35**	1,419
Funded status	**$ (98)**	$ (100)

BALANCE SHEET

The amounts recognized in the Consolidated Balance Sheets consisted of the following:

As at millions of Canadian dollars		**December 31 2021**		December 31 2020
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Other current liabilities	**$ (7)**	**$ (20)**	$ (4)	$ (19)
Long-term liabilities	**(100)**	**(270)**	(163)	(290)
Other long-term assets	**185**	**23**	13	20
Amount included in deferred income tax	**(8)**	**1**	(4)	(1)
AOCI and regulatory assets, net of tax	**230**	**90**	443	107
Net amount recognized	**$ 300**	**$ (176)**	$ 285	$ (183)

AMOUNTS RECOGNIZED IN AOCI AND REGULATORY ASSETS

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI or regulatory assets. The following table summarizes the change in AOCI and regulatory assets:

millions of Canadian dollars	Regulatory assets	Actuarial (gains) losses
Defined Benefit Pension Plans		
Balance, January 1, 2021	$ 279	$ 160
Amortized in current period	(24)	(21)
Current year addition to AOCI or regulatory assets	(61)	(109)
Change in foreign exchange rate	(2)	–
Balance, December 31, 2021	$ 192	$ 30
Non-pension benefits plans		
Balance, January 1, 2021	$ 110	$ (4)
Amortized in current period	(2)	(3)
Current year addition to AOCI or regulatory assets	(16)	7
Change in foreign exchange rate	(1)	–
Balance, December 31, 2021	$ 91	$ –

	2021		2020	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses (gains)	**$ 30**	**$ –**	$ 160	$ (4)
Regulatory assets	**192**	**91**	279	110
Total AOCI and regulatory assets before deferred income taxes	**222**	**91**	439	106
Amount included in deferred income tax assets	**8**	**(1)**	4	1
Net amount in AOCI and regulatory assets	**$ 230**	**$ 90**	$ 443	$ 107

BENEFIT COST COMPONENTS

Emera's net periodic benefit cost included the following:

As at millions of Canadian dollars	2021		Year ended December 31 2020	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 43**	**$ 5**	$ 46	$ 5
Interest cost	**67**	**8**	84	10
Expected return on plan assets	**(132)**	**(1)**	(141)	(1)
Current year amortization of:				
Actuarial losses (gains)	**21**	**3**	15	–
Past service costs (gains)	**–**	**–**	(1)	–
Regulatory assets (liability)	**24**	**2**	25	–
Total	**$ 23**	**$ 17**	$ 28	$ 14

The expected return on plan assets is determined based on the market-related value of plan assets of $2,151 million as at January 1, 2021 (2020 – $2,476 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a five-year period.

PENSION PLAN ASSET ALLOCATIONS

Emera's investment policy includes discussion regarding the investment philosophy, the level of risk which the Company is prepared to accept with respect to the investment of the Pension Funds, and the basis for measuring the performance of the assets. Central to the policy is the target asset allocation by major asset categories. The objective of the target asset allocation is to diversify risk and to achieve asset returns that meet or exceed the plan's actuarial assumptions. The diversification of assets reduces the inherent risk in financial markets by requiring that assets be spread out amongst various asset classes. Within each asset class, a further diversification is undertaken through the investment in a broad range of investment and non-investment grade securities. Emera's target asset allocation is as follows:

Canadian Pension Plans

Asset class	Target Range at Market
Short-term securities	0% to 5%
Fixed income	35% to 50%
Equities:	
Canadian	12% to 22%
Non-Canadian	30% to 55%

Non-Canadian Pension Plans

Asset class	Target Range at Market Weighted Average
Fixed income	30% to 50%
Equities	50% to 70%

Pension Plan assets are overseen by the respective Management Pension Committees in the sponsoring companies. All pension investments are in accordance with policies approved by the respective Board of Directors of each sponsoring company.

The following tables set out the classification of the methodology used by the Company to fair value its investments:

millions of Canadian dollars					**December 31, 2021**
	NAV	**Level 1**	**Level 2**	**Total**	**Percentage**
Cash and cash equivalents	**$ –**	**$ 60**	**$ –**	**$ 60**	**2%**
Net in-transits	**–**	**(84)**	**–**	**(84)**	**(3)%**
Equity securities:					
Canadian equity	**–**	**97**	**–**	**97**	**4%**
US equity	**–**	**366**	**–**	**366**	**14%**
Other equity	**–**	**215**	**–**	**215**	**8%**
Fixed income securities:					
Government	**–**	**–**	**132**	**132**	**5%**
Corporate	**–**	**–**	**117**	**117**	**4%**
Other	**–**	**8**	**3**	**11**	**–%**
Mutual funds	**–**	**86**	**–**	**86**	**3%**
Other	**–**	**1**	**(1)**	**–**	**–%**
Open-ended investments measured at NAV (1)	**952**	**–**	**–**	**952**	**35%**
Common collective trusts measured at NAV (2)	**750**	**–**	**–**	**750**	**28%**
Total	**$ 1,702**	**$ 749**	**$ 251**	**$ 2,702**	**100%**

millions of Canadian dollars					December 31, 2020
	NAV	Level 1	Level 2	Total	Percentage
Cash and cash equivalents	$ –	$ 68	$ –	$ 68	3%
Net in-transits	–	(99)	–	(99)	(4)%
Equity securities:					
Canadian equity	–	154	–	154	6%
US equity	–	380	–	380	15%
Other equity	–	243	–	243	9%
Fixed income securities:					
Government	–	–	119	119	5%
Corporate	–	–	141	141	5%
Other	–	10	3	13	–%
Mutual funds	–	88	–	88	3%
Other	–	(3)	(4)	(7)	–%
Open-ended investments measured at NAV (1)	801	–	–	801	31%
Common collective trusts measured at NAV (2)	704	–	–	704	27%
Total	$ 1,505	$ 841	$ 259	$ 2,605	100%

(1) NAV investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAV's are calculated daily and the funds honor subscription and redemption activity regularly.

(2) The common collective trusts are private funds valued at NAV. The NAVs are calculated based on bid prices of the underlying securities. Since the prices are not published to external sources, NAV is used as a practical expedient. Certain funds invest primarily in equity securities of domestic and foreign issuers while others invest in long duration U.S. investment grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The funds honor subscription and redemption activity regularly.

Refer to note 16 for more information on the fair value hierarchy and inputs used to measure fair value.

POST-RETIREMENT BENEFIT PLANS

There are no assets set aside to pay for most of the Company's post-retirement benefit plans. As is common practice, post-retirement health benefits are paid from general accounts as required. The primary exceptions to this is the NMGC Retiree Medical Plan, which is fully funded.

INVESTMENTS IN EMERA

As at December 31, 2021 and 2020, the assets related to the pension funds and post-retirement benefit plans do not hold any material investments in Emera or its subsidiaries securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

CASH FLOWS

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2022	$ 41	$ 20
Expected benefit payments		
2022	153	21
2023	162	22
2024	162	22
2025	165	22
2026	169	22
2027–2031	872	104

ASSUMPTIONS

The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans:

	2021		2020	
(weighted average assumptions)	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Benefit obligation – December 31:				
Discount rate – past service	**3.05%**	**2.81%**	2.49%	2.48%
Discount rate – future service	**3.18%**	**2.92%**	2.64%	2.51%
Rate of compensation increase	**3.31%**	**3.29%**	2.89%	3.04%
Health care trend – initial (next year)	**–**	**5.09%**	–	5.64%
– ultimate	**–**	**3.77%**	–	4.35%
– year ultimate reached		**2042**		2038
Benefit cost for year ended December 31:				
Discount rate – past service	**2.49%**	**2.48%**	3.17%	3.28%
Discount rate – future service	**2.64%**	**2.51%**	3.21%	3.28%
Expected long-term return on plan assets	**5.86%**	**–%**	6.29%	3.25%
Rate of compensation increase	**2.89%**	**3.04%**	3.34%	3.70%
Health care trend – initial (current year)	**–**	**5.64%**	–	5.91%
– ultimate	**–**	**4.35%**	–	4.37%
– year ultimate reached		**2038**		2038

Actual assumptions used differ by plan.

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan's current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated cash flows from the pension plan.

DEFINED CONTRIBUTION PLAN

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2021 was $45 million (2020 – $45 million).

22. Goodwill

The change in goodwill for the year ended December 31 is due to the following:

millions of Canadian dollars	**2021**	2020
Balance, January 1	**$ 5,720**	$ 5,835
Change in foreign exchange rate	**(24)**	(115)
Balance, December 31	**$ 5,696**	$ 5,720

Goodwill is subject to an annual assessment for impairment at the reporting unit level. The goodwill on Emera's Consolidated Balance Sheets at December 31, 2021, primarily relates to TECO Energy and GBPC. Emera's reporting units with goodwill are Tampa Electric, PGS, NMGC, and GBPC.

In 2021, Emera performed a qualitative impairment assessment for Tampa Electric, PGS and NMGC, concluding that the fair value of the reporting units exceeded their respective carrying amounts, and as such, no quantitative assessments were performed and no impairment charges were recognized.

Goodwill on Emera's Consolidated Balance Sheets at December 31, 2021, included $68 million (2020 – $68 million) related to GBPC. In 2021, the Company performed a quantitative impairment assessment using a discounted cash flow analysis. This assessment estimated that the fair value of the reporting unit exceeded its carrying value, including goodwill, by approximately 12 per cent. Adverse changes in assumptions used could result in a future impairment.

23. Short-Term Debt

Emera's short-term borrowings consist of commercial paper issuances, advances on revolving and non-revolving credit facilities and short-term notes. Short-term debt and the related weighted-average interest rates as at December 31 consisted of the following:

millions of Canadian dollars	2021	Weighted average interest rate	2020	Weighted average interest rate
Tampa Electric Company ("TEC")				
Advances on term, revolving and accounts receivable facilities	**$ 945**	**0.58%**	$ 987	0.89%
Emera				
Non-revolving term facility	**400**	**0.96%**	400	0.94%
Bank indebtedness	**6**	**–%**	–	–%
TECO Finance				
Advances on revolving credit and term facilities	**355**	**1.20%**	205	1.46%
NMGC				
Advances on revolving credit facilities	**25**	**1.20%**	21	1.22%
GBPC				
Advances on revolving credit facilities	**10**	**5.25%**	11	5.25%
NSPI				
Bank indebtedness	**1**	**–%**	1	–%
Short-term debt	**$ 1,742**		$ 1,625	

The Company's total short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	Maturity	2021	2020
Tampa Electric Company – revolving credit facility	2026	**$ 1,014**	$ 1,019
TECO Energy/TECO Finance – revolving credit facility	2026	**507**	509
Emera – non-revolving term facility	2022	**400**	400
TEC – term loan	2022	**634**	382
TEC – accounts receivable revolving credit facility		**–**	191
NMGC – revolving credit facility	2026	**158**	159
GBPC – revolving credit facility	on demand	**16**	17
Total		**$ 2,729**	$ 2,677
Less:			
Advances under revolving credit and term facilities		**1,735**	1,624
Letters of credit issued within the credit facilities		**4**	4
Total advances under available facilities		**1,739**	1,628
Available capacity under existing agreements		**$ 990**	$ 1,049

The weighted average interest rate on outstanding short-term debt at December 31, 2021 was 0.83 per cent (2020 – 1.01 per cent).

RECENT SIGNIFICANT FINANCING ACTIVITY BY SEGMENT

Florida Electric Utilities

On December 17, 2021, TEC entered into a $500 million USD unsecured, non-revolving credit facility with a maturity date of December 16, 2022. The credit facility contains customary representations and warranties, events of default, financial and other covenants and bears interest based on either the London Inter-Bank Offered Rate ("LIBOR"), prime rate, or the federal funds rate, plus a margin.

On December 17, 2021, TEC amended and restated its $800 million USD revolving credit facility. The amendment extended the maturity date from March 22, 2023 to December 17, 2026. There were no other significant changes in commercial terms from the prior agreement.

On May 25, 2021, TEC established a commercial paper program. Amounts available under the commercial paper program may be borrowed, repaid and reborrowed with the aggregate amount of the notes outstanding at any time not to exceed $800 million USD. The full amount of commercial paper issued is backed by TEC's credit facility and results in an equal amount of its credit facility being considered drawn and unavailable.

As a result of the $800 million USD senior notes issuance (refer to note 25), on March 23, 2021, TEC repaid its $300 million USD non-revolving term loan. TEC also repaid its $150 million USD accounts receivable collateralized borrowing facility and the agreement subsequently matured and terminated on March 22, 2021.

Gas Utilities and Infrastructure

On December 17, 2021, NMGC amended and restated its $125 million USD revolving credit facility. The amendment extended the maturity date from March 22, 2023 to December 17, 2026. There were no other significant changes in commercial terms from the prior agreement.

Other

On December 17, 2021, TECO Finance amended and restated its $400 million USD revolving credit facility. The amendment extended the maturity date from March 22, 2023 to December 17, 2026. There were no other significant changes in commercial terms from the prior agreement.

On December 3, 2021, Emera extended the maturity date of its $400 million non-revolving term loan from December 16, 2021 to December 16, 2022. There were no other significant changes in commercial terms from the prior agreement.

24. Other Current Liabilities

As at millions of Canadian dollars	**December 31 2021**	December 31 2020
Accrued charges	**$ 157**	$ 141
Accrued interest on long-term debt	**75**	71
Pension and post-retirement liabilities (note 21)	**27**	23
Sales and other taxes payable	**6**	6
Income tax payable	**6**	1
Other	**95**	98
	$ 366	$ 340

25. Long-Term Debt

Bonds, notes and debentures are at fixed interest rates and are unsecured unless noted below. Included are certain bankers' acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year.

Long-term debt as at December 31 consisted of the following:

millions of Canadian dollars	Weighted average interest rate [1] 2021	2020	Maturity	2021	2020
Emera					
Bankers acceptances, LIBOR loans	Variable	Variable	2026	**$ 378**	$ 263
Unsecured fixed rate notes	2.90%	2.90%	2023	**500**	500
Fixed to floating subordinated notes (USD) [2]	6.75%	6.75%	2076	**1,521**	1,528
				$ 2,399	$ 2,291
Emera Finance					
Unsecured senior notes (USD)	3.65%	3.86%	2024–2046	**$ 3,487**	$ 3,501
TECO Finance					
Tampa Electric [3]					
Fixed rate notes and bonds (USD)	4.15%	4.53%	2022–2051	**$ 3,683**	$ 3,268
PGS					
Fixed rate notes and bonds (USD)	3.78%	4.58%	2022–2051	**$ 660**	$ 429
NMGC					
Fixed rate notes and bonds (USD)	3.11%	4.30%	2026–2051	**$ 488**	$ 465
Non-revolving term facility, floating rate	Variable		2022	**101**	
				$ 589	$ 465
NMGI					
Fixed rate notes and bonds (USD)	3.64%	3.64%	2024	**$ 190**	$ 191
NSPI					
Discount notes	Variable	Variable	2026	**$ 376**	$ 291
Medium term fixed rate notes	5.14%	5.14%	2025–2097	**2,665**	2,665
				$ 3,041	$ 2,956
EBP					
Senior secured credit facility	Variable	Variable	2025	**$ 249**	$ 249
ECI					
Secured senior notes (USD)	Variable	Variable	2026	**$ 84**	$ 106
Amortizing fixed rate notes (USD)	3.97%	3.92%	2022–2026	**104**	100
Non-revolving term facility, floating rate	Variable	Variable	2025	**28**	28
Non-revolving term facility, fixed rate	2.36%	2.60%	2025–2026	**101**	68
Secured fixed rate senior notes [4]	4.43%	4.39%	2022–2035	**161**	174
				$ 478	$ 476
Adjustments					
Fair market value adjustment – TECO Energy acquisition [5]				**$ 3**	$ 5
Debt issuance costs				**(121)**	(110)
Amount due within one year				**(462)**	(1,382)
				$ (580)	$ (1,487)
Long-Term Debt				**$ 14,196**	$ 12,339

(1) Weighted average interest rate of fixed rate long-term debt.
(2) In 2021, the company recognized $102 million in interest expense (2020 – $109 million) related to its fixed to floating subordinated notes.
(3) A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.
(4) Notes are issued and payable in either USD, BBD or East Caribbean Dollar (XCD).
(5) On acquisition of TECO Energy, Emera recorded a fair market value adjustment on the unregulated long-term debt acquired. The fair market value adjustment is amortized over the remaining term of the debt.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	Maturity	2021	2020
Emera – revolving credit facility (1)	June 2026	**$ 900**	$ 900
NSPI – revolving credit facility (1)	December 2026	**600**	600
ECI – revolving credit facilities	2022-2032	**27**	28
Total		**1,527**	1,528
Less:			
Borrowings under credit facilities		**770**	569
Letters of credit issued inside credit facilities		**124**	31
Use of available facilities		**894**	600
Available capacity under existing agreements		**$ 633**	$ 928

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $50 million.

DEBT COVENANTS

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements. Emera's significant covenants are listed below:

	Financial Covenant	Requirement	As at December 31, 2021
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.57 : 1

RECENT SIGNIFICANT FINANCING ACTIVITY BY SEGMENT

Florida Electric Utility

On May 15, 2021, TEC repaid its $278 million USD, 5.4 per cent notes upon maturity. The notes were repaid using existing credit facilities.

On March 18, 2021, TEC completed an issuance of $800 million USD senior notes. The issuance included $400 million USD senior notes that bear interest at a rate of 2.40 per cent with a maturity date of March 15, 2031 and $400 million USD senior notes that bear interest at a rate of 3.45 per cent with a maturity date of March 15, 2051.

Canadian Electric Utilities

On December 3, 2021, NSPI amended its operating credit facility to extend the maturity from October 2024 to December 2026. There were no other significant changes in commercial terms from the prior agreement.

Other Electric Utilities

On December 16, 2021, GBPC entered into a $75 million USD 4.00 per cent term loan with a maturity date of December 31, 2026. Proceeds from this loan were used to repay existing, non-revolving term loans totaling $55 million USD and to fund operations.

Gas Utilities and Infrastructure

On July 16, 2021, Brunswick Pipeline extended the maturity date of its $250 million credit facility from May 17, 2023 to June 30, 2025. There were no other significant changes in commercial terms from the prior agreement.

On March 25, 2021, NMGC entered into a $100 million USD unsecured, non-revolving credit facility with a maturity date of September 23, 2022. The credit facility contains customary representations and warranties, events of default, financial and other covenants and bears interest based on either the LIBOR, prime rate, or the federal funds rate, plus a margin.

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

Other

On July 23, 2021, Emera extended the maturity date of its $900 million unsecured committed revolving credit facility from June 30, 2024 to June 30, 2026. There were no other significant changes in commercial terms from the prior agreement.

On June 4, 2021 Emera US Finance LP completed an issuance of $750 million USD senior notes. The issuance included $450 million USD senior notes that bear interest at a rate of 2.64 per cent with a maturity date of June 15, 2031 and $300 million USD senior notes that bear interest at a rate of 0.83 per cent with a maturity date of June 15, 2024. The USD senior notes are guaranteed by Emera and Emera US Holdings Inc., a wholly owned Emera subsidiary.

From the $750 million USD senior notes issuance discussed above, on June 15, 2021, Emera US Finance LP repaid its previously outstanding $750 million USD senior notes on maturity.

LONG-TERM DEBT MATURITIES

As at December 31, long-term debt maturities, including capital lease obligations, for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2022	2023	2024	2025	2026	Thereafter	Total
Emera	$ –	$ 500	$ –	$ –	$ 1,899	$ –	$ 2,399
Emera US Finance LP	–	–	571	–	951	1,965	3,487
Tampa Electric	285	–	–	–	–	3,398	3,683
PGS	32	–	–	–	–	628	660
NMGC	101	–	–	–	89	399	589
NMGI	–	–	190	–	–	–	190
NSPI	–	–	–	125	416	2,500	3,041
EBP	–	–	–	249	–	–	249
ECI	44	90	66	130	124	24	478
Total	$ 462	$ 590	$ 827	$ 504	$ 3,479	$ 8,914	$ 14,776

26. Asset Retirement Obligations

AROs mostly relate to reclamation of land at the thermal, hydro and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment and a pipeline site. Certain hydro, transmission and distribution assets may have additional AROs that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the fair value of any related ARO cannot be made.

The change in ARO for the years ended December 31 is as follows:

millions of Canadian dollars	**2021**	2020
Balance, January 1	**$ 178**	$ 185
Additions	**1**	10
Liabilities settled (1)	**(13)**	(25)
Accretion included in depreciation expense	**10**	9
Accretion deferred to regulatory asset (included in property, plant and equipment)	**(2)**	(3)
Other	**1**	1
Change in foreign exchange rate	**(1)**	1
Balance, December 31	**$ 174**	$ 178

(1) Tampa Electric produces ash and other by-products, collectively known as CCR's, at its Big Bend and Polk power stations. The decreases in ARO in 2021 and 2020 are due to the closure of CCR management facilities.

27. Commitments and Contingencies

A. COMMITMENTS

As at December 31, 2021, contractual commitments (excluding pensions and other post-retirement obligations, long-term debt and asset retirement obligations) 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
Transportation (1)	$ 563	$ 437	$ 372	$ 323	$ 297	$ 2,627	$ 4,619
Purchased power (2)	231	227	244	242	235	1,967	3,146
Fuel, gas supply and storage	694	104	45	40	25	–	908
Capital projects	359	93	3	1	1	–	457
Long-term service agreements (3)	49	66	47	32	26	83	303
Equity investment commitments (4)	240	–	–	–	–	–	240
Leases and other (5)	15	14	14	12	4	116	175
Demand side management	44	1	1	–	–	–	46
	$ 2,195	$ 942	$ 726	$ 650	$ 588	$ 4,793	$ 9,894

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $142 million related to a gas transportation contract between PGS and SeaCoast through 2040.

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

(3) 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.

(4) Emera has a commitment to make equity contributions to the LIL.

(5) 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. As part of NSPI's 2020 through 2022 fuel stability plan, rates have been set to include $164 million and $162 million for 2021 and 2022, respectively. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval. Any difference between the amounts included in the NSPI fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM. On August 9, 2021, NSPML filed a final capital cost application with the UARB seeking approval to recover capital costs associated with the Maritime Link and approval of NSPML's 2022 assessment. In December 2021, NSPML obtained an interim decision from the UARB approving interim rates beginning January 1, 2022, until receipt of the UARB's decision on the application. On February 9, 2022, the UARB issued its decision relating to the Maritime Link Project, approving NSPML's requested rate base of approximately $1.8 billion less costs that would not otherwise have been recoverable if incurred by NSPI. For further information on the UARB decision, refer to note 7.

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

Emera has committed to obtain certain transmission rights for Nalcor, 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 commenced, and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Leases and other" in the above table.

B. LEGAL PROCEEDINGS

TECO Guatemala Holdings ("TGH")

Prior to Emera's acquisition of TECO Energy in 2016, TGH, a wholly owned subsidiary of TECO Energy, divested of its indirect investment in the Guatemala electricity sector, but retained certain claims against the Republic of Guatemala ("Guatemala"). In 2013, TGH asserted an arbitration claim against Guatemala with the International Centre for the Settlement of Investment Disputes ("ICSID") under the Dominican Republic Central America – United States Free Trade Agreement. The arbitration concerned TGH's allegation that Guatemala unfairly set the distribution tariff for a local distribution company which harmed TGH's investment in that company. A tribunal established by the ICSID ruled in favour of TGH (the "First Award") and in November 2020, Guatemala made a payment of approximately $38 million USD in full and final satisfaction of the First Award.

On September 23, 2016, TGH had filed a request for resubmission to arbitration seeking damages in addition to those awarded in the First Award. On May 13, 2020, an ICSID tribunal awarded TGH additional damages and costs against Guatemala of more than $35 million USD plus interest (the "Second Award"). TGH subsequently requested a reconsideration of the interest quantum awarded in connection with this Second Award. On October 16, 2020, the tribunal granted TGH's request for additional interest. The additional amount is approximately $2 million USD. On February 12, 2021, Guatemala filed an application for annulment of the Second Award with ICSID. On March 31, 2021, ICSID constituted an ad hoc Committee to oversee the annulment proceeding. On May 17, 2021, the ad hoc Committee issued (i) a decision continuing the stay of enforcement of the Second Award until the committee renders its decision on Guatemala's application for annulment and (ii) an order with dates for briefings on the annulment and a hearing commencing July 27, 2022. Guatemala filed its Memorial on Annulment on August 25, 2021. TGH's Counter-Memorial on Annulment was filed on December 8, 2021. To date, the total of the Second Award, with interest, is approximately $62 million USD. Results to date do not reflect any benefit of the Second Award.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a potentially responsible party ("PRP") for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as at December 31, 2021, TEC has estimated its financial liability to be $18 million ($14 million USD), primarily at PGS. This estimate assumes that other involved PRPs are credit-worthy entities. This amount has been accrued and is primarily reflected in the long-term liability section under "Other long-term liabilities" on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites are expected to be paid over many years.

The estimated amounts represent only the portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC's experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are believed to be currently credit-worthy and are likely to continue to be credit-worthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's actual percentage of the remediation costs. Other factors that could impact these estimates include additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in base rate proceedings.

Other Legal Proceedings

Emera and its subsidiaries may, from time to time, be involved in other legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. PRINCIPAL FINANCIAL RISKS AND UNCERTAINTIES

Emera believes the following principal financial risks could materially affect the Company in the normal course of business. Risks associated with derivative instruments and fair value measurements are discussed in note 15 and note 16.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach to risk management. 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 and includes oversight of the Company's Enterprise Risk Management framework, including the identification, assessment, monitoring and management of enterprise risks.

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 investments, 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.

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 Canadian dollar and, particularly, the US dollar, which could positively or adversely affect results.

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

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

Liquidity and Capital Market Risk

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

Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions, and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in property, plant and equipment and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The 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 and regulatory framework, the ability to recover costs and earn returns, diversification, leverage, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes and other severe weather events. A decrease in a credit rating could result in higher interest rates in future financings, 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.

Interest Rate Risk

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital investments, 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 ROE's are likely to fall in times of reducing interest rates and rise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Commodity Price Risk

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

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

Regulated Utilities

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

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

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.

To measure commodity price risk exposure, Emera Energy employs a number of controls and processes, including an estimated value-at-risk ("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.

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.

D. 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, 2021:

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.

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.

In 2021, NSPI issued guarantees in the amount of $15 million USD on behalf of its subsidiary, NS Power Energy Marketing Incorporate ("NSPEMI"), to secure obligations under purchase agreements with third-party suppliers and $85 million USD related to a 15-year natural gas transportation commitment. NSPI has $118 million USD (2020 – $18 million USD) of guarantees outstanding with terms of varying lengths and will be renewed as required.

The Company has standby letters of credit and surety bonds in the amount of $148 million USD (December 31, 2020 – $55 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 2022. The amount committed as at December 31, 2021 was $64 million (December 31, 2020 – $63 million).

Collaborative Arrangements

For the years ended December 31, 2021 and 2020, the Company has identified the following material collaborative arrangements:

Through NSPI, the Company is a participant in three wind energy projects in Nova Scotia. The percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets. NSPI has power purchase arrangements to purchase the entire net output of the projects and, therefore, NSPI's portion of the revenues are recorded net within regulated fuel for generation and purchased power. NSPI's portion of operating expenses is recorded in OM&G expenses. In 2021, NSPI recognized $18 million net expense (2020 – $19 million) in "Regulated fuel for generation and purchased power" and $3 million (2020 – $3 million) in OM&G.

28. Cumulative Preferred Stock

Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

			December 31, 2021		December 31, 2020	
	Annual Dividend per Share	Redemption Price per Share	**Issued and Outstanding**	**Net Proceeds**	Issued and Outstanding	Net Proceeds
Series A	$ 0.5456	$ 25.00	**4,866,814**	**$ 119**	4,866,814	$ 119
Series B	Floating	$ 25.00	**1,133,186**	**$ 28**	1,133,186	$ 28
Series C	$ 1.1802	$ 25.00	**10,000,000**	**$ 245**	10,000,000	$ 245
Series E	$ 1.1250	$ 25.25	**5,000,000**	**$ 122**	5,000,000	$ 122
Series F	$ 1.0505	$ 25.00	**8,000,000**	**$ 195**	8,000,000	$ 195
Series H	$ 1.2250	$ 25.00	**12,000,000**	**$ 295**	12,000,000	$ 295
Series J	$ 1.0625	$ 25.00	**8,000,000**	**$ 196**	–	$ –
Series L	$ 1.1500	$ 25.00	**9,000,000**	**$ 222**	–	$ –
Total			**58,000,000**	**$ 1,422**	41,000,000	$ 1,004

First Preferred Shares, Series J

On April 6, 2021, Emera issued 8 million, 4.25 per cent Cumulative Minimum Rate Reset First Preferred Shares, Series J ("First Preferred Shares, Series J") at $25.00 per share for gross proceeds of $200 million ($196 million, net of after-tax issuance costs).

First Preferred Shares, Series L

On September 24, 2021, Emera issued 9 million, 4.60 per cent Cumulative Redeemable First Preferred Shares, Series L ("First Preferred Shares, Series L") at $25.00 per share for gross proceeds of $225 million ($222 million, net of after-tax issuance costs).

Characteristics of the First Preferred Shares:

First Preferred Shares (1) (2)	Initial Yield (%)	Current Annual Dividend ($)	Minimum Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a One for One Basis
Fixed rate reset (3) (4)						
Series A	4.400	0.5456	1.84	August 15, 2025	25.00	Series B
Series C	4.100	1.1802	2.65	August 15, 2023	25.00	Series D
Series F	4.202	1.0505	2.63	February 15, 2025	25.00	Series G
Minimum rate reset (3) (4)						
Series B	2.393	Floating	1.84	August 15, 2025	25.00	Series A
Series H	4.900	1.2250	4.90	August 15, 2023	25.00	Series I
Series J	4.250	1.0625	4.25	May 15, 2026	25.00	Series K
Perpetual fixed rate						
Series E (5)	4.500	1.1250			25.25	
Series L (6)	4.600	1.1500		November 15, 2026	25.00	

(1) Holders are entitled to receive fixed or floating cumulative cash dividends when declared by the Board of Directors of the Corporation.
(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding First Preferred Shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.
(3) On the redemption and/or conversion option date the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed or floating dividend rate, which for Series A, C, F and H is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield (Series H annual reset rate must be a minimum of 4.90 per cent) and for Series B equals the Government of Treasury Bill Rate on the applicable reset date, plus 1.84 per cent.
(4) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their Shares into an equal number of Cumulative Redeemable First Preferred Shares of a specified series. The Company has the right to redeem the outstanding Preferred Shares, Series D, Series G and Series I shares without the consent of the holder every five years thereafter for cash, in whole or in part at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption and $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption in the case of redemptions on any other date after August 15, 2023, February 15, 2025 and August 15, 2023, respectively. The reset dividend yield for Series I equals the Government of Treasury Bill Rate on the applicable reset date, plus 2.54 per cent.
(5) First Preferred Shares, Series E are redeemable at $25.25 to August 15, 2022 and $25.00 per share thereafter.
(6) First Preferred Shares, Series L are redeemable at $26.00 on or after November 15, 2026 to November 15, 2027, decreasing $0.25 each year until November 15, 2030 and $25.00 per share thereafter.

First Preferred Shares are neither redeemable at the option of the shareholder nor have a mandatory redemption date. They are classified as equity and the associated dividends is deducted on the Consolidated Statements of Income before arriving at "Net income attributable to common shareholders" and is shown on the Consolidated Statement of Equity as a deduction from retained earnings.

The First Preferred Shares of each series rank on a parity with the First Preferred Shares of every other series and are entitled to a preference over the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares, for only so long as the dividends remain in arrears, will be entitled to attend any meeting of shareholders of the Company at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at any such meeting.

29. Non-Controlling Interest in Subsidiaries

As at millions of Canadian dollars		December 31 2021		December 31 2020
Preferred shares of GBPC	$	14	$	14
Domlec		20		20
	$	34	$	34

PREFERRED SHARES OF GBPC:

Authorized:

10,000 non-voting cumulative redeemable variable perpetual preferred shares.

Issued and outstanding:	2021 number of shares		millions of dollars	2020 number of shares		millions of dollars
Outstanding as at December 31	10,000	$	14	10,000	$	14

GBPC NON-VOTING CUMULATIVE VARIABLE PERPETUAL PREFERRED STOCK:

The preferred shares are redeemable by GBPC after June 17, 2021, at $1,000 Bahamian per share plus accrued and unpaid dividends and are entitled to a 6.0 per cent per annum fixed cumulative preferential dividend to be paid semi-annually.

The Preferred Shares rank behind GBPC's current and future secured and unsecured debt and ahead of all of GBPC's current and future common stock.

30. Supplementary Information to Consolidated Statements of Cash Flows

For the millions of Canadian dollars		Year ended December 31 2021		2020
Changes in non-cash working capital:				
Inventory	$	(84)	$	6
Receivables and other current assets		(364)		187
Accounts payable		289		55
Other current liabilities		7		(31)
Total non-cash working capital	$	(152)	$	217
Supplemental disclosure of cash paid (received):				
Interest	$	603	$	679
Income taxes	$	24	$	(148)
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	$	214	$	199
Reclassification of long-term debt from current to non-current		–		256
(Decrease) Increase in accrued capital expenditures	$	(45)	$	17

31. Stock-Based Compensation

EMPLOYEE COMMON SHARE PURCHASE PLAN AND COMMON SHAREHOLDERS DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Eligible employees may participate in Emera's Employee Common Share Purchase Plan. As of December 31, 2021, the plan allows employees to make cash contributions of a minimum of $25 to a maximum of $20,000 CAD or $15,000 USD per year for the purpose of purchasing common shares of Emera. The Company also contributes 20 per cent of the employees' contributions to the plan.

The plan allows the reinvestment of dividends for all participants except for where it is prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares (2020 – 7 million common shares). As at December 31, 2021, Emera is in compliance with this requirement.

Compensation cost for shares issued by Emera for the year ended December 31, 2021 under the Employee Common Share Purchase Plan was $3 million (2020 – $2 million) and is included in OM&G on the Consolidated Statements of Income.

The Company also has a Common Shareholders Dividend Reinvestment and Share Purchase Plan ("Dividend Reinvestment Plan") or ("DRIP"), which provides an opportunity for shareholders to reinvest dividends and purchase common shares. This plan provides for a discount of up to 5 per cent from the average market price of Emera's common shares for common shares purchased in connection with the reinvestment of cash dividends. The discount was 2 per cent in 2021.

STOCK-BASED COMPENSATION PLANS

Stock Option Plan

The Company has a stock option plan that grants options to senior management of the Company for a maximum term of 10 years. The option price of the stock options is the closing market price of the stocks on the day before the option is granted. The maximum aggregate number of shares issuable under this plan is 14.7 million shares. As at December 31, 2021, Emera is in compliance with this requirement.

Stock options vest in 25 per cent increments on the first, second, third and fourth anniversaries of the date of the grant. If an option is not exercised within 10 years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of stocks to be optioned to any optionee shall not exceed five per cent of the issued and outstanding common stocks on the date the option is granted.

Unless a stock option has expired, vested options may be exercised within the 27 months following the option holders date of retirement, six months following a termination without just cause or death, and within sixty days following the date of termination for just cause or resignation. If stock options are not exercised within such time, they expire.

The Company uses the Black-Scholes valuation model to estimate the compensation expense related to its stock-based compensation and recognizes the expense over the vesting period on a straight-line basis.

The following table shows the weighted average fair values per stock option along with the assumptions incorporated into the valuation models for options granted, for the year-ended December 31:

	2021	2020
Weighted average fair value per option	**$ 3.63**	$ 3.58
Expected term (1)	**5 years**	5 years
Risk-free interest rate (2)	**0.60%**	1.33%
Expected dividend yield (3)	**5.00%**	4.09%
Expected volatility (4)	**19.14%**	14.10%

(1) The expected term of the option awards is calculated based on historical exercise behaviour and represents the period of time that the options are expected to be outstanding.
(2) Based on the Bank of Canada five-year government bond yields.
(3) Incorporates current dividend rates and historical dividend increase patterns.
(4) Estimated using the five-year historical volatility.

The following table summarizes stock option information for 2021:

	Total Options		Non-Vested Options (1)	
	Number of Options	Weighted Average Exercise Price per Share	Number of Options	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2020	2,267,782	$ 46.62	1,293,850	$ 2.69
Granted	653,600	51.12	653,600	3.63
Exercised	(331,078)	40.97	N/A	N/A
Vested	N/A	N/A	(494,975)	2.49
Options outstanding December 31, 2021	**2,590,304**	**$ 48.48**	**1,452,475**	**$ 3.18**
Options exercisable December 31, 2021 (2) (3)	**1,137,829**	**$ 44.86**		

(1) As at December 31, 2021, there was $3 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 3 years (2020 – $2 million, 3 years).
(2) As at December 31, 2021, the weighted average remaining term of vested options was 6 years with an aggregate intrinsic value of $21 million (2020 – $12 million, 6 years).
(3) As at December 31, 2021, the fair value of options that vested in the year was $1 million (2020 – $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2021 was $2 million (2020 – $1 million), which is included in OM&G on the Consolidated Statements of Income.

As at December 31, 2021, cash received from option exercises was $14 million (2020 – $19 million). The total intrinsic value of options exercised for the year ended December 31, 2021 was $6 million (2020 – $6 million). The range of exercise prices for the options outstanding as at December 31, 2021 was $32.35 to $60.03 (2020 – $32.06 to $60.03).

SHARE UNIT PLANS

The Company has DSU, PSU and RSU plans. The plans and the liabilities are marked-to-market at the end of each period based on an average common share price at the end of the period.

Deferred Share Unit Plans

Under the Directors' DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation, subject to requirements to receive a minimum portion of their annual retainer in DSUs. Directors' fees are paid on a quarterly basis and, at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera's common shares, the Director's DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan. Following retirement or resignation from the Board, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by Emera's closing common share price on the date DSUs are redeemed.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50 per cent of the value of their actual annual incentive award (25 per cent in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Payments are usually made in cash. At the sole discretion of the Management Resources and Compensation Committee ("MRCC"), payments may be made in the form of actual shares.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or by achieving certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2021 is presented in the following table:

	Employee DSU	Weighted Average Grant Date Fair Value	Director DSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2020	661,998	$ 37.17	591,124	$ 41.69
Granted including DRIP	93,710	49.64	101,403	51.25
Exercised	(145,107)	36.61	(78,162)	37.57
Outstanding and exercisable as at December 31, 2021	**610,601**	**$ 39.22**	**614,365**	**$ 43.80**

Compensation cost recognized for employee and director DSU's for the year ended December 31, 2021 was $9 million (2020 – $2 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2021 were $3 million (2020 – $1 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2021 for employees was $39 million (2020 – $36 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2021 for directors was $39 million (2020 – $32 million). Cash payments made during the year ended December 31, 2021 associated with the DSU plan was $11 million (2020 – $11 million).

Performance Share Unit Plan

Under the PSU plan, certain executive and senior employees are eligible for long-term incentives payable through the PSU plan. PSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional PSUs. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios.

A summary of the activity related to employee PSUs for the year ended December 31, 2021 is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value
Outstanding as at December 31, 2020	1,126,529	$ 47.16	$ 68
Granted including DRIP	323,610	52.83	
Exercised	(464,290)	48.13	
Forfeited	(33,914)	47.78	
Outstanding as at December 31, 2021	**951,935**	**$ 48.60**	**$ 66**

Compensation cost recognized for the PSU plan for the year ended December 31, 2021 was $12 million (2020 – $27 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2021 were $3 million (2020 – $7 million). Cash payments made during the year ended December 31, 2021 associated with the PSU plan was $29 million (2020 – $29 million).

Restricted Share Unit Plan

Under the RSU plan, certain executive and senior employees are eligible for long-term incentives payable through the RSU plan. RSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. RSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional RSUs. The RSU value varies according to the Emera common share market price.

RSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios.

A summary of the activity related to employee RSUs for the year ended December 31, 2021 is presented in the following table:

	Employee RSU	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value
Outstanding as at December 31, 2020	166,275	$ 54.62	$ 10
Granted including DRIP	184,498	54.66	
Exercised	(232)	54.62	
Forfeited	(6,589)	54.63	
Outstanding as at December 31, 2021	**343,952**	**$ 54.64**	**$ 24**

Compensation cost recognized for the RSU plan for the year ended December 31, 2021 was $8 million (2020 – $ 4 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2021 were $2 million (2020 – $ 1 million). Cash payments made during the year ended December 31, 2021 associated with the RSU plan was nil (2020 – nil).

32. Variable Interest Entities

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera is not the primary beneficiary since it does not have the controlling financial interest of NSPML. When the critical milestones were achieved, Nalcor Energy was deemed the primary beneficiary of the asset for financial reporting purposes as it has authority over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link. Thus, Emera began recording the Maritime Link as an equity investment.

BLPC has established a Self-Insurance Fund ("SIF"), primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. ECI holds a variable interest in the SIF for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that, in substance, the activities of the SIF are being conducted on behalf of ECI's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because ECI, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. Any withdrawal of SIF fund assets by the Company would be subject to existing regulations. Emera's consolidated VIE in the SIF is recorded as "Other long-term assets", "Restricted cash" and "Regulatory liabilities" on the Consolidated Balance Sheets. Amounts included in restricted cash represent the cash portion of funds required to be set aside for the BLPC SIF.

The Company has identified certain long-term purchase power agreements that meet the definition of variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

The following table provides information about Emera's portion of material unconsolidated VIEs:

As at	**December 31, 2021**		December 31, 2020	
millions of Canadian dollars	**Total Assets**	**Maximum Exposure to Loss**	Total Assets	Maximum Exposure to Loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 533**	**$ 11**	$ 547	$ 16

33. Subsequent Events

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 14, 2022, the date the financial statements were issued.

Emera Leadership and Board

As of March 31, 2022

Emera Leadership

Scott Balfour
President and
Chief Executive Officer,
Emera Inc.

Rob Bennett
President and Chief
Executive Officer,
Emera Technologies LLC

Greg Blunden
Chief Financial Officer,
Emera Inc.

Archie Collins
President and Chief
Executive Officer,
Tampa Electric

Peter Gregg
President and Chief
Executive Officer,
Nova Scotia Power

Karen Hutt
Executive Vice President,
Business Development
and Strategy,
Emera Inc.

Rick Janega
Chief Operating Officer,
Electric Utilities, Canada
and Caribbean,
Emera Inc.

Chief Executive Officer,
Emera Newfoundland
& Labrador

Bruce Marchand
Chief Legal and Compliance
Officer,
Emera Inc.

Dan Muldoon
Executive Vice President,
Project Development
and Operations Support,
Emera Inc.

Michael Roberts
Chief Human Resources
Officer,
Emera Inc.

Ryan Shell
President,
New Mexico Gas Company

Judy Steele
President and
Chief Operating Officer,
Emera Energy

Helen Wesley
President,
Peoples Gas

Board of Directors

Jackie Sheppard
Chair, Emera Inc.
Calgary, Alberta

Scott Balfour
Halifax, Nova Scotia

James Bertram
Calgary, Alberta

Henry Demone
Lunenburg, Nova Scotia

Paula Gold-Williams
San Antonio, Texas

Kent Harvey
New York, New York

Lynn Loewen
Westmount, Quebec

John Ramil
Tampa, Florida

Ian Robertson
Oakville, Ontario

Andrea Rosen
Toronto, Ontario

Richard Sergel
Boston, Massachusetts

Karen Sheriff
Toronto, Ontario

Jochen Tilk
Toronto, Ontario

Shareholder Information

For general inquiries about our Company, please contact our corporate office:

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Information regarding Company news and initiatives, including our 2021 Annual Report, is available on our website:
www.emera.com

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This Annual Report contains forward-looking information. Actual future results may differ materially. Additional financial and operational information is filed electronically with various securities commissions in Canada through the System for Electronic Document Analysis and Retrieval (SEDAR).

Share Listings

Toronto Stock Exchange (TSX)
Common shares: EMA
Preferred shares: EMA.PR.A, EMA.PR.B, EMA.PR.C, EMA.PR.E, EMA.PR.F, EMA.PR.H, EMA.PR.J and EMA.PR.L
Barbados Stock Exchange (BSE)
Depositary receipts: EMABDR
Bahamas International Securities Exchange (BISX)
Depositary receipts: EMAB

Shares Outstanding

Common shares: 261,065,175 (as of December 31, 2021)

Dividends Paid in 2021

Emera Inc. paid common share dividends of $0.6375 per quarter in Q1, Q2 and Q3 (annualized rate of $2.55 per common share) and $0.6625 in Q4 (annualized rate of $2.65 per common share), for an effective annual common share dividend rate of $2.575 per common share.

Dividend Payments in 2022

Subject to approval by the Board of Directors, dividends for Emera Inc. are payable on or about the 15th of February, May, August and November. A first quarter common share dividend of $0.6625, a Series A First Preferred Share dividend of $0.1364, a Series B First Preferred Share dividend of $0.1253, a Series C First Preferred Share dividend of $0.29506, a Series E First Preferred Share dividend of $0.28125, a Series F First Preferred Share dividend of $0.26263, a Series H First Preferred Share dividend of $0.30625, a Series J First Preferred Share dividend of $0.265625 and a Series L First Preferred Share dividend of $0.2875 were declared and paid on February 15, 2022.

Dividend Reinvestment and Share Purchase Plan

Emera's Dividend Reinvestment and Share Purchase Plan is available to shareholders who reside in Canada. The plan provides shareholders with a convenient and economical means of acquiring additional common shares through the reinvestment of dividends up to a five per cent discount. In 2021, the discount was two per cent. Plan participants may also contribute cash payments of up to $5,000 per quarter. Participants of the plan pay no commissions, service charges or brokerage fees for shares purchased under the plan. Please contact Investor Services if you have questions or wish to receive an enrollment form.

Direct Deposit Service

Registered shareholders may have dividends deposited directly to any bank account in Canada. To arrange this service, please contact TSX Trust Company. Beneficial shareholders should contact their financial intermediary.

Quarterly Earnings

Quarterly earnings are expected to be announced in May, August and November 2022. Year-end results for 2021 were released in February 2022.

Representation in the TSX Composite, TSX Capped Utilities, TSX60 and select MSCI and FTSE World indexes

Our Operations

As of March 31, 2022

TAMPA ELECTRIC

Vertically integrated electric utility serving about 800,000 customers in west central Florida.

NOVA SCOTIA POWER

Vertically integrated electric utility serving more than 525,000 customers in Nova Scotia.

PEOPLES GAS

Natural gas utility serving 445,000 customers in Florida.

NEW MEXICO GAS

Natural gas utility serving 540,000 customers in New Mexico.

EMERA CARIBBEAN

Vertically integrated electric utilities serving more than 184,000 customers on the islands of Barbados, Grand Bahama, Dominica and St. Lucia.

EMERA NEWFOUNDLAND & LABRADOR

Owns and operates the Maritime Link and manages Emera's investment in an associated project.

EMERA ENERGY

Energy marketing and trading, asset management and optimization in Canada and the US.

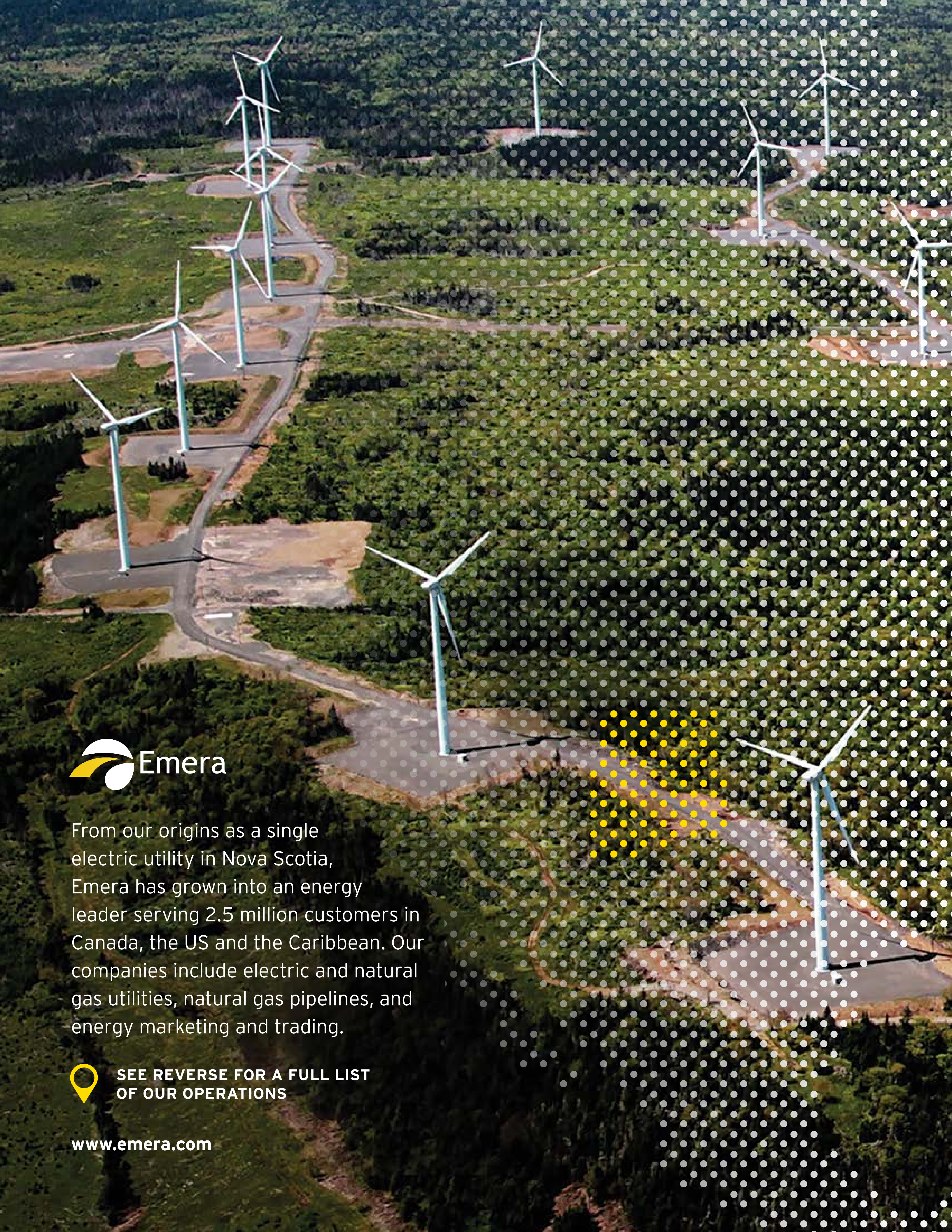
EMERA NEW BRUNSWICK

Owns and operates the Brunswick pipeline, a 145-kilometre natural gas pipeline in New Brunswick.

EMERA TECHNOLOGIES

A technology company focused on finding new, innovative ways to deliver renewable and resilient energy to customers.

www.emera.com



Emera

From our origins as a single electric utility in Nova Scotia, Emera has grown into an energy leader serving 2.5 million customers in Canada, the US and the Caribbean. Our companies include electric and natural gas utilities, natural gas pipelines, and energy marketing and trading.

SEE REVERSE FOR A FULL LIST OF OUR OPERATIONS

www.emera.com